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Contents

Federal Register

Vol. 89, No. 113

Tuesday, June 11, 2024

Agricultural Marketing Service

NOTICES

Agency Information Collection Activities; Proposals, Submissions, and Approvals, 49145–49146

Agriculture Department

See Agricultural Marketing Service

See Animal and Plant Health Inspection Service

See Forest Service

Animal and Plant Health Inspection Service

PROPOSED RULES

National Poultry Improvement Plan and Auxiliary Provisions, 49107–49118

Antitrust Division

NOTICES

Proposed Final Judgment and Competitive Impact Statement:

State of Ohio et al. v. National Collegiate Athletics Assn., 49194–49211

Bureau of Consumer Financial Protection

RULES

Personal Financial Data Rights; Industry Standard-Setting, 49084–49091

Centers for Medicare & Medicaid Services

NOTICES

Agency Information Collection Activities; Proposals, Submissions, and Approvals, 49178–49179

Civil Rights Commission

NOTICES

Hearings, Meetings, Proceedings, etc.:

North Carolina Advisory Committee, 49146–49147

Commerce Department

See Economic Development Administration

See International Trade Administration

See National Institute of Standards and Technology

See National Oceanic and Atmospheric Administration

Defense Department

NOTICES

Hearings, Meetings, Proceedings, etc.:

Listening Sessions on Draft Environmental Justice Strategy Approach, 49160–49162

Denali Commission

NOTICES

Fiscal Year 2025 Draft Work Plan, 49162–49163

Economic Development Administration

NOTICES

Agency Information Collection Activities; Proposals, Submissions, and Approvals:

Indigenous Communities Survey and Interview Collection Instruments, 49147–49148

Education Department

NOTICES

Agency Information Collection Activities; Proposals, Submissions, and Approvals:

Evaluation of the REL Southeast Early Literacy Toolkit, 49163–49164

Reaffirmation Agreement, 49164–49165

Employee Benefits Security Administration

NOTICES

Exemption:

Certain Prohibited Transaction Restrictions; UBS AG Located in Zurich, Switzerland, 49213–49231

Employment and Training Administration

NOTICES

Program Year 2024 Workforce Innovation and Opportunity Act:

National Farmworker Jobs Program Preliminary State Allotments, 49234–49237

Work Opportunity Tax Credit Program, 49231–49234

Energy Department

See Federal Energy Regulatory Commission

Environmental Protection Agency

RULES

Air Quality State Implementation Plans; Approvals and Promulgations:

Michigan; Definitions, 49100–49101

Per- and Polyfluoroalkyl Substances National Primary Drinking Water Regulation; Correction, 49101–49104

PROPOSED RULES

Air Quality State Implementation Plans; Approvals and Promulgations:

Michigan; Definitions, 49120–49121

Significant New Uses:

Certain Chemical Substances (22–4.5e), 49121–49144

Certain Chemical Substances (23–3.5e), 49770–49796

NOTICES

Hearings, Meetings, Proceedings, etc.:

Clean Air Act Advisory Committee, 49176

Proposed Settlement Agreement, Stipulation, Order, and Judgment, etc.:

Aberdeen Contaminated Groundwater Site, Aberdeen, NC, 49175

Bennett Landfill Fire Superfund Site, Chester, SC, 49175–49176

Federal Accounting Standards Advisory Board

NOTICES

Hearings, Meetings, Proceedings, etc.:

Appointments Panel, 49176

Federal Aviation Administration

RULES

Airworthiness Directives:

GA8 Airvan (Pty) Ltd Airplanes, 49091–49094

International Aero Engines, AG Engines, 49094–49099

PROPOSED RULES

Airspace Designations and Reporting Points:

Claremont, NH, 49118–49119

NOTICES

Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Advisory Circular: Reporting of Laser Illumination of Aircraft, 49255–49256

Limited Waiver of the Slot Usage Requirement:
Staffing-Related Relief Concerning Operations at Ronald Reagan Washington National Airport, John F. Kennedy International Airport, LaGuardia Airport, and Newark Liberty International Airport, October 27, 2024, through March 29, 2025 (Winter 2024/2025) and March 30, 2025, through October 25, 2025 (Summer 2025), 49256–49259

Federal Energy Regulatory Commission**RULES**

Building for the Future through Electric Regional Transmission Planning and Cost Allocation, 49280–49586

NOTICES

Authorization for Continued Project Operation:
Bangor-Pacific Hydro Associates, 49168
New York Power Authority, 49172, 49174

Combined Filings, 49165–49168

Environmental Assessments; Availability, etc.:
Green Lake Water Power Co., Proposed Project Relicense, 49168–49169
Ketchikan Public Utilities, Proposed Project Relicense, 49169

Environmental Impact Statements; Availability, etc.:
FirstLight MA Hydro LLC, Northfield Mountain LLC, 49166
Great River Hydro, LLC, 49167

Filing:
Western Area Power Administration, 49173–49174

Hearings, Meetings, Proceedings, etc.:
FFP Project 101, LLC, 49174

Initial Market-Based Rate Filings Including Requests for Blanket Section 204 Authorizations:
Bayou Galion Solar Project, LLC, 49174–49175
Big Rock ESS Assets LLC, 49172
Capon Bridge Solar, LLC, 49171

Records Governing Off-the-Record Communications, 49169–49170

Request under Blanket Authorization:
Cheniere Corpus Christi Pipeline, LP, 49170–49171

Staff Attendance:
North American Electric Reliability Corp. Joint Reliability and Security Technical Committee and Standards Committee Meeting, etc., 49173

Federal Maritime Commission**NOTICES**

Complaint, 49176–49177

Federal Motor Carrier Safety Administration**NOTICES**

Exemption Application:
Commercial Driver's License; 3 North LLC, 49263–49264
Commercial Driver's License; Oregon Department of Transportation, 49265–49267

Qualification of Drivers; Epilepsy and Seizure Disorders, 49261–49263, 49267–49268

Qualification of Drivers; Hearing, 49259–49261, 49264–49265

Financial Crimes Enforcement Network**NOTICES**

Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Due Diligence Programs for Correspondent Accounts for Foreign Financial Institutions and for Private Banking Accounts, 49273–49277

Food and Drug Administration**NOTICES**

Hearings, Meetings, Proceedings, etc.:
Emerging Drug Safety Technology Meetings, Program Announcement, 49179–49180

Forest Service**NOTICES**

Hearings, Meetings, Proceedings, etc.:
Modoc Resource Advisory Committee, 49146

General Services Administration**NOTICES**

Environmental Impact Statements; Availability, etc.:
International Falls Land Port of Entry Modernization and Expansion Project in International Falls, MN, Record of Decision, 49177–49178

Health and Human Services Department

See Centers for Medicare & Medicaid Services

See Food and Drug Administration

See National Institutes of Health

NOTICES

Agency Information Collection Activities; Proposals, Submissions, and Approvals, 49180–49181

Housing and Urban Development Department**RULES**

Removal of Obsolete Regulations of the National Housing Act; Correction, 49099–49100

NOTICES

Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Semi-Annual Labor Standards Enforcement Report—Local Contracting Agencies, 49182–49183

Interior Department

See Land Management Bureau

See National Park Service

International Trade Administration**NOTICES**

Agency Information Collection Activities; Proposals, Submissions, and Approvals:
Application for Export Trade Certificate of Review, 49157

Antidumping or Countervailing Duty Investigations, Orders, or Reviews:
Certain Magnesia Carbon Bricks from the People's Republic of China, 49148–49149
Certain Steel Nails from the United Arab Emirates, 49150–49152
Chlorinated Isocyanurates from the People's Republic of China, 49149–49150
Forged Steel Fittings from the People's Republic of China, 49154–49157
Silicomanganese from India, 49152–49154

International Trade Commission**NOTICES**

Antidumping or Countervailing Duty Investigations, Orders, or Reviews:

Vanillin from China, 49192–49193

Investigations; Determinations, Modifications, and Rulings, etc.:

Brass Rod from Brazil, India, Mexico, South Africa, and South Korea, 49193–49194

Justice Department

See Antitrust Division

NOTICES

Agency Information Collection Activities; Proposals, Submissions, and Approvals:

eForm Access Request/User Registration, 49211–49212

September 11th Victim Compensation Fund Claim Form, 49212–49213

Labor Department

See Employee Benefits Security Administration

See Employment and Training Administration

See Occupational Safety and Health Administration

Land Management Bureau**NOTICES**

Agency Information Collection Activities; Proposals, Submissions, and Approvals:

Resource Advisory Council Application, 49183–49184

National Endowment for the Humanities**NOTICES**

Hearings, Meetings, Proceedings, etc.:

Humanities Panel, 49237–49238

National Foundation on the Arts and the Humanities

See National Endowment for the Humanities

National Highway Traffic Safety Administration**NOTICES**

Agency Information Collection Activities; Proposals, Submissions, and Approvals:

Human Interaction with Driving Automation Systems, 49268–49273

National Institute of Standards and Technology**NOTICES**

Agency Information Collection Activities; Proposals, Submissions, and Approvals:

Generic Clearance for Decision Science Data Collections, 49157–49158

National Institutes of Health**NOTICES**

Hearings, Meetings, Proceedings, etc.:

Center for Scientific Review, 49181

National Cancer Institute, 49181

National Institute on Alcohol Abuse and Alcoholism, 49181–49182

National Oceanic and Atmospheric Administration**RULES**

Fisheries of the Caribbean, Gulf of Mexico, and South Atlantic:

Reef Fish Fishery of the Gulf of Mexico; 2024 Red Snapper Private Angling Component Accountability Measure in Federal Waters off Alabama, Florida, and Mississippi, 49104–49105

Fisheries of the Northeastern United States:

Summer Flounder Fishery; Quota Transfer from North Carolina to Virginia, 49105–49106

NOTICES

Guidance:

New Regional Ocean Partnerships, 49160

Hearings, Meetings, Proceedings, etc.:

Sanctuary System Business Advisory Council, 49159–49160

Permits; Applications, Issuances, etc.:

Marine Mammals and Endangered and Threatened Species, 49158–49159

National Park Service**NOTICES**

Disposition:

Bureau of Reclamation, Upper Colorado Basin Region, Provo, UT, 49190

Hearings, Meetings, Proceedings, etc.:

Cape Cod National Seashore Advisory Commission, 49184–49185

Intended Disposition:

General Services Administration, Fort Worth, TX, 49188–49189

Inventory Completion:

Bureau of Land Management, Canyons of the Ancients Visitors Center and Museum, Dolores, CO, 49187

Grand Rapids Public Museum, Grand Rapids, MI, 49191

Los Rios Community College District, Sacramento, CA, 49185–49186

Mukwonago Community Library, Mukwonago, WI, 49191–49192

Peabody Museum of Archaeology and Ethnology, Harvard University, Cambridge, MA, 49189

Western Washington University, Department of Anthropology, Bellingham, WA, 49187–49188

Repatriation of Cultural Items:

Pipe Spring National Monument, Fredonia, AZ, 49190–49191

School for Advanced Research, Santa Fe, NM, 49184

University of Michigan, Ann Arbor, MI, 49186–49187

Nuclear Regulatory Commission**RULES**

Regulatory Guide:

Qualification of Class 1E Battery Chargers, Inverters, and Uninterruptible Power Supply Systems for

Production and Utilization Facilities, 49083–49084

NOTICES

Facility Operating and Combined Licenses:

Applications and Amendments Involving Proposed No Significant Hazards Considerations, etc., 49238–49245

Occupational Safety and Health Administration**PROPOSED RULES**

Emergency Response Standard, 49119–49120

Postal Regulatory Commission**NOTICES**

New Postal Products, 49245

Postal Service**NOTICES**

Meetings; Sunshine Act, 49245–49246

Presidential Documents**PROCLAMATIONS**

Special Observances:

National Day of Remembrance of the 80th Anniversary of
D-Day (Proc. 10774), 49081–49082**Securities and Exchange Commission****NOTICES**Agency Information Collection Activities; Proposals,
Submissions, and Approvals, 49249–49250

Application:

HPS Corporate Lending Fund et al., 49246–49247

Self-Regulatory Organizations; Proposed Rule Changes:

ICE Clear Credit LLC, 49252–49254

NYSE Arca, Inc., 49247–49249

NYSE National, Inc., 49250–49252

Public Company Accounting Oversight Board, 49588–
49728, 49730–49767**State Department****NOTICES**Annual Determination and Certification of Shrimp-
Harvesting Nations, 49254–49255**Transportation Department***See* Federal Aviation Administration*See* Federal Motor Carrier Safety Administration*See* National Highway Traffic Safety Administration**Treasury Department***See* Financial Crimes Enforcement Network

Separate Parts In This Issue**Part II**Energy Department, Federal Energy Regulatory
Commission, 49280–49586**Part III**

Securities and Exchange Commission, 49588–49728

Part IV

Securities and Exchange Commission, 49730–49767

Part VEnvironmental Protection Agency, 49770–49796

Reader AidsConsult 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](https://public.govdelivery.com/accounts/USGPOOFR/subscriber/new), enter your e-mail
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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:**

10774.....49081

9 CFR**Proposed Rules:**

56.....49107

145.....49107

146.....49107

147.....49107

10 CFR

50.....49083

52.....49083

12 CFR

1033.....49084

14 CFR

39 (2 documents) 49091,
49094

Proposed Rules:

71.....49118

18 CFR

35.....49280

24 CFR

236.....49099

29 CFR**Proposed Rules:**

1910.....49119

40 CFR

52.....49100

141.....49101

Proposed Rules:

52.....49120

721 (2 documents) 49121,
49770

50 CFR

622.....49104

648.....49105

Presidential Documents

Title 3—

Proclamation 10774 of June 5, 2024

The President

National Day of Remembrance of the 80th Anniversary of D-Day

By the President of the United States of America

A Proclamation

On the evening of June 6, 1944, President Franklin D. Roosevelt broadcast a prayer for the Nation. At the time, war was raging in Europe, and Hitler controlled most of it. Freedom and democracy were under assault around the world. But on that day, hope had landed on the beaches of Normandy when 73,000 Americans joined the Allied forces to carry out one of the greatest military missions of all time—a mission that would become known as D-Day. Knowing the fate of the free world rested in their hands, President Roosevelt asked our Nation to pray for these courageous service members' strength as they "set upon a mighty endeavor, a struggle to preserve our Republic, our religion, and our civilization, and to set free a suffering humanity." On the 80th anniversary of D-Day, may we thank these service members for their bravery and sacrifice. May we honor their heroism, which liberated a continent and saved the world. And may we recommit to the future they fought and which many died for.

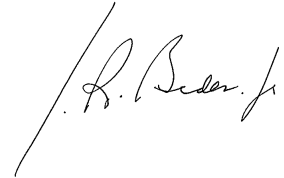
The brave Airmen, Coast Guardsmen, Sailors, Soldiers, and Marines who fought on D-Day faced unparalleled resistance. Nazi Germany had reinforced the Atlantic Wall, lining miles of dangerous cliffs and rocky coastlines with landmines, beach and water obstacles, and machine gunners while also reinforcing its bunkers. So, when 7,000 vessels carrying nearly 160,000 service members from eight Allied countries approached Normandy, victory was never guaranteed. Our paratroopers that jumped behind enemy lines in the night and other military forces had to endure barrages of gunfire, trek through barbed wire, and climb steep sea walls. Over 2,500 Americans made the ultimate sacrifice, giving their lives so that the whole world might know freedom.

Today, we remember all the Americans who laid down their lives on D-Day to help end the tyranny of fascism across Europe, liberate oppressed peoples, and ensure the flame of liberty would burn bright around the world. Their success marked the beginning of the end of Nazi brutality, World War II, and the Holocaust—one of the darkest chapters in human history. It set the foundations of an enduring peace that still helps guide international cooperation and affairs today. We owe these service members, who represent the greatest of the Greatest Generation, as well as their families a debt of gratitude that we can never fully repay.

As we reflect on the sacrifices made on D-Day, we are reminded that freedom is not free and it has never been guaranteed. Every generation has to earn it, fight for it, and defend it in the battle between autocracy and democracy—between the greed of a few and the rights of many. Eighty years after our Nation's brave Airmen, Coast Guardsmen, Sailors, Soldiers, and Marines embarked on D-Day—and as Americans everywhere answered the call to prayer and filled their hearts and homes with hope—may we honor the faith they kept in our Nation and their legacy by upholding the future that they died for—one grounded in freedom, democracy, opportunity, and equality for all.

NOW, THEREFORE, I, JOSEPH R. BIDEN JR., President of the United States of America, by virtue of the authority vested in me by the Constitution and the laws of the United States, do hereby proclaim June 6, 2024, as a National Day of Remembrance of the 80th Anniversary of D-Day. I call upon all Americans to observe this day with programs, ceremonies, and activities that honor those who fought and died so that men and women they had never met might know what it is to be free.

IN WITNESS WHEREOF, I have hereunto set my hand this fifth day of June, 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.

A handwritten signature in black ink, appearing to read "J. R. Biden Jr.", with a long, sweeping horizontal line extending to the left.

Rules and Regulations

Federal Register

Vol. 89, No. 113

Tuesday, June 11, 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.

NUCLEAR REGULATORY COMMISSION

10 CFR Parts 50 and 52

[NRC–2022–0151]

Regulatory Guide: Qualification of Class 1E Battery Chargers, Inverters, and Uninterruptible Power Supply Systems for Production and Utilization Facilities

AGENCY: Nuclear Regulatory Commission.

ACTION: Final guide; issuance.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) is issuing Revision 1 to Regulatory Guide (RG), 1.210, “Qualification of Class 1E Battery Chargers, Inverters, and Uninterruptible Power Supply Systems for Production and Utilization Facilities.” This RG describes an approach that is acceptable to the staff of the NRC to meet regulatory requirements for the qualification of safety related or Class 1E battery chargers, inverters, and uninterruptible power supply systems for production and utilization facilities.

DATES: Revision 1 to RG 1.210 is available on June 11, 2024.

ADDRESSES: Please refer to Docket ID NRC–2022–0151 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–2022–0151. 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 individuals 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. The ADAMS accession number for each document referenced (if it is available in ADAMS) is provided the first time that it is mentioned in this document.

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Revision 1 to RG 1.210 and the regulatory analysis may be found in ADAMS under Accession Nos. ML23202A242 and ML22160A589, respectively.

Regulatory guides are not copyrighted, and NRC approval is not required to reproduce them.

FOR FURTHER INFORMATION CONTACT:

Michael A. Eudy, Office of Nuclear Regulatory Research, telephone: 301–415–3104; email: Michael.Eudy@nrc.gov and Adakou Foli, Office of Nuclear Reactor Regulation, telephone: 301–415–1984; email: Adakou.Foli@nrc.gov. Both are staff of the U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001.

SUPPLEMENTARY INFORMATION:

I. Discussion

The NRC is issuing a revision in the NRC’s “Regulatory Guide” series. This series was developed to describe methods that are acceptable to the NRC staff for implementing specific parts of the agency’s regulations, to explain techniques that the staff uses in evaluating specific issues or postulated events, and to describe information that the staff needs in its review of applications for permits and licenses.

The proposed Revision 1 to RG 1.210 was issued with a temporary identification of Draft Regulatory Guide, DG–1412. This revision endorses, with clarifications, the Institute of Electrical and Electronic Engineers (IEEE) Standard (Std.) 650–2017, “IEEE

Standard for Qualification of Class 1E Static Battery Chargers, Inverters, and Uninterruptible Power Supply Systems for Nuclear Power Generating Stations.”

II. Additional Information

The NRC published notice of the availability of DG–1412 in the **Federal Register** on February 1, 2023 (88 FR 6672) for a 30-day public comment period. The public comment period closed on March 3, 2023. Public comments on DG–1412 and the staff responses to the public comments are available in ADAMS under Accession No. ML23202A244.

As noted in the **Federal Register** on December 9, 2022 (87 FR 75671), this document is being published in the “Rules” section of the **Federal Register** to comply with publication requirements under chapter I of title 1 the *Code of the Federal Register* (CFR).

III. Congressional Review Act

This RG is a rule as defined in the Congressional Review Act (5 U.S.C. 801–808). However, the Office of Management and Budget has not found it to be a major rule as defined in the Congressional Review Act.

IV. Backfitting, Forward Fitting, and Issue Finality

RG 1.210, Revision 1, does not constitute backfitting as defined in 10 CFR 50.109, “Backfitting,” and as described in NRC Management Directive (MD) 8.4, “Management of Backfitting, Forward Fitting, Issue Finality, and Information Requests”; does not constitute forward fitting as that term is defined and described in MD 8.4; and does not affect the issue finality of an approval issued under 10 CFR part 52. As explained in RG 1.210, applicants and licensees are not required to comply with the positions set forth in this RG.

V. Submitting Suggestions for Improvement of Regulatory Guides

A member of the public may, at any time, submit suggestions to the NRC for improvement of existing RGs or for the development of new RGs. Suggestions can be submitted on the NRC’s public website at <https://www.nrc.gov/reading-rm/doc-collections/reg-guides/contactus.html>. Suggestions will be considered in future updates and enhancements to the “Regulatory Guide” series.

Dated: June 6, 2024.

For the Nuclear Regulatory Commission.
Meraj Rahimi,
*Chief, Regulatory Guide and Programs
 Management Branch, Division of Engineering,
 Office of Nuclear Regulatory Research.*
 [FR Doc. 2024-12761 Filed 6-10-24; 8:45 am]
 BILLING CODE 7590-01-P

CONSUMER FINANCIAL PROTECTION BUREAU

12 CFR Part 1033

[Docket No. CFPB-2023-0052]

RIN 3170-AA78

Required Rulemaking on Personal Financial Data Rights; Industry Standard-Setting

AGENCY: Consumer Financial Protection Bureau.

ACTION: Final rule.

SUMMARY: The Consumer Financial Protection Bureau (CFPB) is finalizing in part its proposed rule on consumer data rights under section 1033 of the Consumer Financial Protection Act. This final rule establishes minimum attributes a standard-setting body must possess to receive CFPB recognition and to issue consensus standards when the full rule is finalized. The CFPB is also releasing its process for how standard setters apply for CFPB recognition.

DATES: This final rule is effective July 11, 2024.

FOR FURTHER INFORMATION CONTACT:

George Karithanom, Regulatory Implementation and Guidance Program Analyst, Office of Regulations, at 202-435-7700 or <https://reginquiries.consumerfinance.gov/>. If you require this document in an alternative electronic format, please contact CFPB_Accessibility@cfpb.gov.

SUPPLEMENTARY INFORMATION:

I. Summary

The CFPB is finalizing certain provisions of its Required Rulemaking on Personal Financial Data Rights (Personal Financial Data Rights rule),¹ which, among other proposed provisions in the rule, sought to promote fair, open, and inclusive industry standard-setting. The CFPB proposed that standards adopted by CFPB-recognized standard setters might be used to facilitate implementation of a final Personal Financial Data Rights rule. Today's rule revises and finalizes part of proposed § 1033.131 (definitions) and all of proposed § 1033.141 (attributes a standard-setting body must

demonstrate in order to be recognized by the CFPB). Included with this rule is a step-by-step guide for how standard setters apply for recognition and how the CFPB will evaluate applications.

II. Background

A. Introduction

Consumer electronic access to personal financial data, including and especially open banking,² holds the potential to intensify consumer-friendly competition and innovation. Fair, open, and inclusive industry standard-setting play a critical role in ensuring the open banking system reaches its full potential to benefit consumers and competition.

By including section 1033 in the Consumer Financial Protection Act of 2010 (CFPA),³ Congress explicitly recognized the importance of personal financial data rights, and section 1033(d) recognizes the importance of standardized formats, especially with regard to data formats. In 2023, the CFPB issued a proposed rule to begin implementing section 1033, with the goal of accelerating the shift to a more open and decentralized system of consumer data access.

The proposed rule reflected the CFPB's preliminary determination that conformance with industry standards would constitute certain evidence of compliance with various substantive provisions of the proposed rule (or, in the case of data formats, would be sufficient for a data provider to be deemed compliant), provided that such standards were issued by a body recognized by the CFPB as possessing certain attributes. The proposed rule set forth the CFPB's view that industry standard setters that operate in a fair, open, and inclusive manner have a critical role to play in ensuring a safe, secure, reliable, and competitive data access framework. In the proposed rule, the CFPB noted that Federal regulations with very granular technical requirements could rapidly become obsolete, while industry-led standard-setting would be better able to keep pace with changes in the market and technology, as long as that standard-setting was fair, open, and inclusive.

U.S. government agencies have been historically involved in the

development and use of standards to meet agency missions and priorities. Office of Management and Budget (OMB) Circular A-119⁴ reflects the U.S. government's commitment to a U.S. industry-led, voluntary consensus standards system. Broad use of such standards enhances the safety and security of products, reduces consumer costs, and expands consumers' options in the marketplace. Additionally, voluntary consensus standards ensure that no faction of industry can use its market power to impose its preferences on the entire market. Further, the use of consensus standards significantly reduces costs to agencies that would otherwise be incurred if agencies had to develop and maintain agency-unique standards.

B. Summary of the Rulemaking Process Outreach and Engagement

The CFPB published its proposed rule on October 31, 2023.⁵ The public comment period on the proposed rule closed on December 29, 2023, and the CFPB received comments from individuals and entities representing various diverse interests. In addition, the CFPB also considered comments received after the comment period closed via ex parte submissions and meetings.⁶ Materials on the record, including all ex parte submissions and summaries of ex parte meetings, are available on the public docket for this rulemaking.⁷

This final rule discusses those substantive comments relevant to the attributes of standard-setting bodies or the process by which the CFPB will recognize standard-setting bodies. For the most part, commenters that addressed the issues discussed in this final rule and in the appended application procedures supported the CFPB's plan to recognize standard setters that are fair, open, and inclusive, and generally agreed with the attributes the CFPB proposed to use to determine whether a standard-setting body was

⁴ OMB Circular A-119 was originally published in 1996; see <https://www.govinfo.gov/content/pkg/FR-1996-12-27/html/96-32917.htm>. The current Circular, effective January 27, 2016, is available at https://www.whitehouse.gov/wp-content/uploads/2020/07/revised_circular_a-119_as_of_1_22.pdf.

⁵ 88 FR 74796 (Oct. 31, 2023). A description of the CFPB's outreach and engagement before issuing the proposed rule, including the CFPB's convening of a small business advisory review panel pursuant to the Small Business Regulatory Enforcement Fairness Act of 1996, is included in the proposal at 74801-02.

⁶ CFPB, Policy on Ex Parte Presentations in Rulemaking Proceedings, 82 FR 18687 (Apr. 21, 2017).

⁷ See <https://www.regulations.gov/docket/CFPB-2023-0052/comments>.

¹ 88 FR 74796 (Oct. 31, 2023).

² This **Federal Register** document generally uses the term "open banking" to refer to the network of entities sharing personal financial data with consumer authorization. Some stakeholders use the term "open finance" because of the role of nondepositories as important data sources. The CFPB views the two terms as interchangeable, but generally uses "open banking" because that term is more commonly used in the United States.

³ The CFPA is title X of the Dodd-Frank Wall Street Reform and Consumer Protection Act, Public Law 111-203, 124 Stat. 1376, 2008 (2010).

fair, open, and inclusive. Some commenters requested that the CFPB alter, clarify, or remove specific provisions of the proposed attributes, or made suggestions for how the CFPB should make its determination as to whether to recognize a given standard-setting body. Other commenters argued that the CFPB does not have legal authority to recognize standard-setting bodies, or critiqued how the proposed rule described a potential recognition process. The CFPB has considered these comments in adopting this final rule. The CFPB will discuss and address all other substantive comments when it finalizes the remainder of the Personal Financial Data Rights rule, including the many comments received concerning the role that adherence to a consensus standard should or should not play in evaluating compliance with the particular underlying provisions of the final rule.⁸ Comments focused on the application procedures described in the appendix are discussed in section IV.C.

Prior to issuing this final rule, in accordance with CFPA sections 1033(e) and 1022(b)(2)(B), the CFPB consulted on several occasions with staff from the prudential regulators⁹ and the Federal Trade Commission to discuss various aspects of the proposed rule, including criteria for and processes with respect to standard-setting bodies.

III. Legal Authority

The CFPB is issuing this final rule pursuant to its authority under the CFPA. As set forth in section 1021 of the CFPA, Congress established the CFPB to ensure that “all consumers have access to markets for consumer financial products and services and that markets for consumer financial products and services are fair, transparent, and competitive.” Congress also authorized the CFPB to exercise its authorities under Federal consumer financial law, including the CFPA, to ensure that, with respect to consumer financial products and services, consumers have “timely and understandable information to make responsible decisions about financial transactions,” “consumers are protected from unfair, deceptive, or abusive acts and practices and from discrimination,” that “markets for consumer financial products and

services operate transparently and efficiently to facilitate access and innovation,” and that “Federal consumer financial law is enforced consistently without regard to the status of a person as a depository institution in order to promote fair competition.”

A. CFPA Section 1033

CFPA section 1033(a) and (b) provide that, subject to rules prescribed by the CFPB, a covered person shall make available to a consumer, upon request, information in the control or possession of the covered person concerning the consumer financial product or service that the consumer obtained from such covered person, subject to certain exceptions. The information must be made available in an electronic form usable by consumers. In addition, CFPA section 1033(d) provides that the CFPB, by rule, shall prescribe standards applicable to covered persons to promote the development and use of standardized formats for information, including through the use of machine-readable files, to be made available to consumers under this section. Recognition of standard-setting bodies that are fair, open, and inclusive can facilitate implementation of these authorities. Further, CFPA section 1033(e) requires that the CFPB consult with the prudential regulators and the FTC to ensure, to the extent appropriate, that certain objectives are met.

B. CFPA Section 1022(b)

CFPA section 1022(b)(1) authorizes the CFPB to, among other things, prescribe rules and issue orders “as may be necessary or appropriate to enable the CFPB to administer and carry out the purposes and objectives of the Federal consumer financial laws, and to prevent evasions thereof.” The CFPA is a Federal consumer financial law. This rule carries out the purposes and objectives of the CFPA and prevents evasions thereof, by requiring standard-setting bodies to apply through the CFPB for recognition to adopt consensus¹⁰ standards.

IV. Discussion of the Final Rule

A. Overview

This final rule identifies the attributes that a standard-setting body must demonstrate in order to be recognized

by the CFPB. It also includes procedures for standard setters to apply for recognition by the CFPB. The following addresses comments on the proposed rule relevant to each topic.

B. Consensus Standards and Recognized Standard Setters

Definitions for Recognized Standard Setter and Consensus Standard

The CFPB proposed in § 1033.131 to define a “qualified industry standard” as a standard issued by a standard-setting body that is fair, open, and inclusive in accordance with proposed § 1033.141(a). The CFPB proposed in § 1033.141 that a standard-setting body is fair, open and inclusive when it satisfies seven requisite attributes: openness, balance, due process, appeals, consensus, transparency, and that the standard-setting body have been recognized by the CFPB as an issuer of qualified industry standards within the last three years.

Some commenters asked the CFPB to clarify when a standard issued by a recognized standard-setting body becomes a consensus standard, and, conversely, when a consensus standard ceases to have consensus status. A trade group commenter suggested that the CFPB remove the language in proposed § 1033.141(a)(7) that a standard-setting body must have been recognized by the CFPB within the last three years, suggesting that this recognition period would make it difficult for industry to use such standards or, appropriate, switch away from them. One commenter expressed concern that the loss of a standard’s status as a consensus standard could cause market uncertainty, because the covered financial institutions would need to identify a different recognized standard setter and possibly have to modify its practices to conform with the consensus standards of that recognized standard setter.

After considering these comments, the CFPB is making several changes to §§ 1033.131 and 1033.141 relating to both standard setters and the standards they issue. First, this final rule replaces the term “qualified industry standard” with “consensus standard,” and adds a definition of “recognized standard setter,” a term not defined in the proposed rule. These editorial changes are intended to better organize the structure of these key terms, enhance readability of the final rule, and adopt terminology that more clearly describes the defined terms.

The definition of “consensus standard” in final § 1033.131 provides additional specificity regarding when a

⁸ Accordingly, the CFPB does not expect its finalization of the remainder of the Personal Financial Data Rights rule to affect the content of this rule. If in finalizing the remainder of the rule the CFPB concludes that this rule should be amended, the CFPB would do so.

⁹ Prudential regulators refer to the Board of Governors of the Federal Reserve System, Federal Deposit Insurance Corporation, National Credit Union Association, and Office of the Comptroller of the Currency.

¹⁰ The proposed rule referred to standards issued by a recognized standard-setting body as “qualified industry standards.” This final rule instead uses the term “consensus standards,” to reflect better the intent of ensuring that the standards are the product of fair, open, and inclusive standard-setting. In addition, in this final rule a standard-setting body recognized by the CFPB will be referred to as a “recognized standard setter.”

given standard is a consensus standard. Final § 1033.131 provides that to be a “consensus standard” the standard must be one that is adopted by a recognized standard setter, and that continues to be maintained by that recognized standard setter. Regarding the commenters’ concern about market uncertainty, the CFPB expects revocation of recognition for a standard setter to be a rare occurrence, and in that event the CFPB would issue guidance to help manage a transition.

The CFPB has determined that it is appropriate to require a recognized standard setter to seek renewal of its recognition on a periodic basis. However, in § 1033.141(a), this final rule extends the maximum duration of the CFPB’s recognition of a standard-setting body from the proposed duration of three years to five years. Periodic review and re-recognition mitigate the risk of outdated standards, which the CFPB’s approach to industry standards was intended in part to avoid. Additionally, periodic review by the CFPB will ensure standard setters carefully mind their governance and procedures and keep them in conformance with the attributes. However, extending the maximum recognition period to five years in this final rule is warranted, for two main reasons. First, a five-year recognition period will mean that, should one or more standard-setting body receive early recognition from the CFPB, such recognition—and by extension their standards’ status as consensus standards—would last further into the period during which industry is initially coming into compliance with the forthcoming Personal Financial Data Rights rule, providing additional certainty to smaller data providers covered by the rule. Additionally, the CFPB expects that reducing the frequency of periodic review and re-recognition by the CFPB will encourage standard-setting bodies to obtain recognition because their standards will retain consensus status for a longer period without the burden of seeking re-recognition.

The CFPB’s Authority To Recognize Standard-Setting Bodies

Several industry commenters disputed the Bureau’s legal authority to recognize standard-setting bodies that would then issue consensus standards for purposes of facilitating implementation of a final Personal Financial Data Rights rule. In response, the CFPB notes that, as discussed above in this final rule, establishing a framework for standard setting is authorized by CFPA section 1033(a) and

(d) and the CFPB’s authority to issue rules under CFPA section 1022(b)(1). The CFPB expects that individual recognition decisions will be authorized by this final rule, by the CFPB’s authority to issue orders under CFPA section 1022(b)(1), and additionally by the CFPB’s authority to issue declaratory orders to “to terminate a controversy or remove uncertainty” under section 554(e) of the Administrative Procedure Act.¹¹

Attributes of Standard-Setting Bodies

Openness

The CFPB proposed to include “openness” as a necessary attribute for CFPB recognition, and that a standard-setting body’s openness would be evaluated by reviewing whether the standard-setting body’s sources, procedures, and processes are open to all interested parties, and whether those interested parties can meaningfully participate in standards development on a non-discriminatory basis.

A few commenters addressed the proposed openness attribute. Consumer advocate commenters supported the explicit inclusion of consumer groups as an interested party for an open standard-setting body. A small number of commenters recommended alterations to the attribute. One industry trade group called for the CFPB to clarify that only the members of the standard-setting body would need to meaningfully participate in the standards development. Additionally, some third-party industry commenters asked the CFPB to clarify that a standard-setting body that is “open” for purposes of the attribute includes all types of financial institutions, including financial technology companies. In support of this consideration, one commenter highlighted what it described as the undue influence of banks in another country’s standard-setting body due to the other country’s exclusion of financial technology voices in the standard-setting body.

This final rule adopts § 1033.141(a)(1) mostly as proposed, with some additional clarifying text. In response to commenter concern that certain financial technology sectors might be excluded if not explicitly mentioned, the CFPB has added explicit reference to “data recipients” as an interested party in this final rule. The inclusion of data recipients also helps ensure that data providers and recipients are not forever compelled to rely on intermediaries with commercial interests that may not consistently align with the advancement

of open banking standards. This final rule does not adopt commenters’ request to limit “openness” to only members of the standard-setting body. As stated in this final rule, the sources of the standard-setting body must be available to all interested parties. This language reiterates that the CFPB expects an “open” standard-setting body to utilize open-source materials that interested parties can reference. Such open-source materials would not truly be open unless they were made available outside the standard-setting body’s membership.

Balance

The CFPB proposed to include “balance” as a necessary attribute for CFPB recognition. The CFPB proposed that a standard-setting body’s balance would be evaluated by the CFPB reviewing whether the standard-setting body’s decision-making power is balanced across all interested parties at all levels of the standard-setting body. Further, the proposed attribute clarifies that balance could be impacted by entities playing multiple roles, such as data provider and third party. Additionally, the CFPB proposed that it could consider the ownership of an entity when reviewing a standard setter’s balance. Finally, the CFPB proposed that balance would include meaningful representation of small and large commercial entities.

A number of commenters addressed this attribute. One consumer advocate commenter expressed their support for the proposed rule’s inclusion of consumer advocates as interested parties in an open standard-setting body. Another consumer advocate commenter noted that some current standards bodies do not provide the same voting rights across categories of membership. A few commenters asked for clarification as to what the CFPB will consider “meaningful representation,” noting the importance of including small entity voices in the decision-making processes. Additionally, one consumer advocate commenter and one industry commenter recommended that a final rule extend balanced representation considerations to any committee or sub-committee involved in the standard setters decision-making processes.

After considering these comments, the CFPB is finalizing the requirement in § 1033.141(a)(2) largely as proposed, with some modifications. To address commenters’ concerns about representation at the committee and sub-committee level, the CFPB has revised this final rule to state that balanced representation must be *reflected* at all levels of the standard-

¹¹ 5 U.S.C. 554(e).

setting body. The additional “reflected” language provides a standard-setting body with some flexibility to arrange adequate committee and sub-committee representation, while also mitigating the possibility that a particular committee or sub-committee’s representation become so unbalanced that it hinders the overall decision-making of the standard-setting body. This final rule does not further define “meaningful representation” because after consideration the CFPB concludes that the additional language reading “[n]o single interest or set of interests dominates decision-making” sufficiently describes the scope of meaningful representation. Finally, to address concerns about weighting of voting rights, this final rule clarifies that if a participant plays multiple roles, the weight of that participant’s role will be factored into the balance consideration. As such, if a participant has a vote as a data provider but their primary business is as a third party, this could suggest that the standard-setting body is not balanced. Similarly, the CFPB can look at the ownership of a participant to determine to what degree the role and form of that entity’s participation in the standard-setting body furthers or hinders the body’s balance.

Due Process and Appeals

The CFPB proposed to include “due process” and “appeals” as necessary attributes for CFPB recognition. The proposed due process attribute would consider whether a standard-setting body uses documented and publicly available policies and procedures and provides a fair and impartial process for resolving conflicting views. The proposed appeals attribute would consider whether the standard-setting body provides an appeals process for the impartial handling of appeals.

A small number of commenters addressed these attributes. A few industry trade groups recommended that a final due process attribute should protect the anonymity of participant dialogue to encourage open dialogue among the members of the standard-setting body. One consumer advocate commenter recommended that a final appeals attribute focus on the process of creating standards, rather than on the standards themselves.

The CFPB is finalizing the proposed due process and appeals attributes with minimal change and a non-substantive structural modification. The structural modification is to combine the appeals and due process attributes into one attribute (now at § 1033.141(a)(3)), because both address similar issues of procedural fairness. Additionally, the

CFPB is finalizing a modification to the appeals attribute that clarifies that the appeals process is available for the impartial handling of *procedural* appeals. The CFPB is finalizing the remainder of the attribute as proposed. Specifically, this final rule does not add requested language about anonymity within the standard-setting body. While anonymity may in some circumstances help create open dialogue, the CFPB is not including in this final rule the explicit availability of participant viewpoint anonymity because such protection is already provided by this final rule. Standard-setting bodies are not precluded from making viewpoints anonymous, so long as such anonymity policies do not have the potential to undermine a final openness, transparency, or due process attribute.

Consensus

The CFPB proposed to include “consensus” as a necessary attribute for CFPB recognition. Specifically, the proposed attribute looks at whether the standards development processes would proceed by consensus, defined as general agreement but not unanimity.

The CFPB received little commenter input concerning the consensus attribute. One third-party trade group recommended that a final rule consider consensus to be when there is consensus within a particular sector. The commenter suggested that if all third parties or all data providers oppose a standard, then that standard should not be adopted. Additionally, one data provider commenter recommended that a final rule consider that the majority of the standards proposed in the Personal Financial Data Rights rulemaking are obligations on data providers, and, as such, consensus should require data providers to be in agreement with a particular decision-making process of the standard-setting body.

The CFPB is finalizing the attribute largely as proposed, and adding language stating that consensus does not *necessarily* require unanimity. This modification is to clarify that general agreement can include unanimous decisions by the members of the standard-setting body. This final rule does not include language stating that a single class of standard-setting group members (like data providers or third parties) could have unilateral power in a standard-setting body. While consensus is important, privileging one group of members would inappropriately give that group unwarranted influence. The provision is also renumbered to § 1033.141(a)(4) to reflect organizational changes.

Transparency

The CFPB proposed to include “transparency” as an attribute for CFPB recognition consideration. Specifically, the proposed attribute would look at whether the procedures or processes for participating in standards development and for developing standards are transparent to participants and publicly available.

Several industry trade groups recommended that a final transparency attribute protect the anonymity of participant dialogue to encourage open dialogue among the participants in the setting of consensus standards. As stated above in the discussion of the proposed due process provision, standard-setting bodies are not precluded from making viewpoints anonymous, so long as such anonymity policies do not have the potential to undermine a final openness, transparency, or due process attribute. Accordingly, for the reasons discussed in the proposal, the CFPB is finalizing the transparency attribute as proposed. The provision is also renumbered to § 1033.141(a)(5) to reflect organizational changes.

Additional Attributes

In response to the CFPB’s request for comment on whether it should include additional attributes when evaluating a standard setter for recognition, at least one commenter suggested that a final rule should adjust the attribute list to account for the relevance of standards that a standard-setting body adopts.

This final rule does not include an additional “relevance” attribute. However, demonstrating the attributes in this final rule is the minimum requirement for recognition; accordingly, the CFPB may consider other information when reviewing an application for recognition, including whether the standard-setting body will adopt and maintain standards relevant to open banking.

C. Procedures for CFPB Recognition of Standard-Setting Bodies

High-Level Comment Summary

A number of commenters on the proposed rule encouraged the CFPB to establish a process for recognizing standard setters as soon as possible. Their comments generally focused on seeking clarity and transparency from the CFPB about this process. Some industry commenters requested that the CFPB publish its recognition procedures for comment.

In response to comments that the CFPB quickly establish a process for recognizing standard-setting bodies, the

CFPB is publishing the procedures included at appendix A. These constitute a rule of agency organization, procedure, or practice, and thus do not require notice and comment under the Administrative Procedure Act.¹² As published, these procedures take account of comments received on the proposed rule regarding procedures for recognizing standard-setting bodies. The CFPB may publish amendments to the procedures from time-to-time as it develops experience with this recognition process and receives stakeholder feedback on them.

Discussion of Procedures for Recognition

The CFPB is providing a plain language guide for how standard setters should apply for recognition, how the CFPB evaluates applications, and what standard setters can expect once recognized. When submitting a request for recognition, the applicant should provide information sufficient to enable a determination by the CFPB of whether the applicant satisfies the requirements for recognition articulated in § 1033.141(a)(1) through (5). Other information provided, such as a description of how the applicant's current and/or anticipated standards relate to open banking, will help the CFPB understand the relevance of the standard setter to open banking.

The procedures also allow for a pre-filing meeting with the CFPB prior to submission of an application, so that the Bureau can provide information about the application process and assist organizations with submitting a complete application. During its review and discussions with the applicant, the CFPB may request additional information from the applicant necessary for the submission to be complete. Once it receives a complete application, the CFPB may publish the application, so as to enable stakeholders who believe the application is deficient to bring the CFPB's attention to any evidence that might substantiate such claims of deficiency.¹³ In this event, the CFPB expects to ask the applicant to provide written responses to any such claims, which the CFPB can then consider as part of its review and assessment of the application. This procedure addresses comments requesting greater public participation in the recognition process.

The CFPB will consider the complete application, including any adverse

evidence provided to the CFPB, to evaluate whether the applicant satisfies the recognition requirements articulated in § 1033.141(a)(1) through (5). The CFPB will also evaluate whether the information provided in the application is accurate and complete, including regarding the applicant's policies and actual practices.

As part of its evaluation of an application, the CFPB will consider how granting a recognition request might support its own role in open banking pursuant to its CFPA section 1033 authority. However, the CFPB is not adopting the recommendation of one trade association commenter that a standard-setting body should not be eligible for CFPB recognition unless it had already promulgated standards central to the safe and efficient operation of open banking. Rather, the CFPB is retaining the flexibility suggested by other commenters that will enable the CFPB to recognize an organization at earlier stages of standards development in a given area. The CFPB emphasizes, however, that a recognition request from an entity that has not adopted, and does not intend to adopt, standards relevant to the CFPB's statutorily-authorized objectives for open banking is unlikely to be prioritized and may not be approved.

In acting on an application, in addition to either recognizing or not recognizing an applicant, the CFPB may provide contingent recognition to an applicant that has presented a satisfactory written plan specifying how and when it will address contingencies that the CFPB has identified. Once the applicant presents sufficient evidence that it has addressed such contingencies, the CFPB may recognize the applicant. The CFPB expects to use contingent recognition, which is not formal recognition under 12 CFR 1033.131, when it determines that an applicant is close to realizing, but has not yet realized, recognition requirements. The availability of contingent recognition responds to a trade association comment on the proposed rule that advocated for a phased approach to recognition, during which the CFPB would—before granting full recognition—offer feedback on steps to full recognition and support standard setters with garnering necessary stakeholder participation for recognition.

Consistent with trade association comments requesting that the CFPB publish a list of standard setters it recognizes, the CFPB will publicly disclose on its website each recognition and contingent recognition, along with the applicable terms and conditions of

each. Some terms and conditions may be tailored to the circumstances of the applicant. For example, if the CFPB grants recognition based on the intention of a standard setter to develop and publish a consensus standard on a given subject matter, the CFPB may condition recognition on good faith efforts to develop a consensus standard in the given area.

Some commenters requested that the CFPB publish denials and include in its procedures a process to appeal such denials. The CFPB will publish denials as required by law, but applicants may also withdraw a pending application at any time for any reason. The CFPB is not providing a specialized appeals process. Consistent with the suggestion of one industry trade association, the CFPB may permit consultation with agency officials to help remedy issues after a submitted application is denied—although the agency intends pre-decisional consultation to minimize recourse to this option.

Next, the procedures describe the interaction between the CFPB and a standard setter once it is recognized. As noted above, each recognized standard setter must agree to a set of applicable terms and conditions. The procedures highlight terms and conditions related to CFPB observation or participation in standard-setting activities, notification requirements on the part of the standard setter, and monitoring of the standard setter by the CFPB. They also explain how a standard setter may request re-recognition.

In view of a trade association comment noting the need for market participants to have adequate time to transition from a consensus standard if the associated standard setter's recognition expires, the procedures state that recognized standard setters intending to apply for re-recognition should do so at least 180 days before their recognition expires. The CFPB may temporarily extend a recognition while a re-recognition application is pending. Both provisions related to re-recognition are intended to reduce the likelihood that a consensus standard loses its status due to a recognition expiring before re-recognition is granted.

Finally, the procedures describe the circumstances under which the CFPB may modify or revoke recognition. One advocacy organization indicated that the CFPB should revoke recognition when requirements of recognition are no longer met. Other industry commenters stated that the CFPB should clarify the circumstances under which recognition may be revoked, and also allow for the standard setter to cure deficiencies.

¹² 5 U.S.C. 553(b).

¹³ If an applicant believes that portions of its application should be treated as confidential, it should consult the CFPB before submitting its application.

The CFPB expects to base a modification or revocation decision, which it would publish on its website, on whether the standard-setting body has failed to comply with applicable terms and conditions, otherwise no longer meets the required attributes, or otherwise no longer warrants recognition. The CFPB also expects to inform the standard setter of reasons for modification or revocation, and to provide the standard setter with an opportunity to address concerns.

V. Effective Date

The CFPB is adopting an effective date of 30 days after the publication of this final rule in the **Federal Register**, consistent with section 553(d) of the Administrative Procedure Act.¹⁴ No later effective date is necessary because this final rule does not impose any obligations on any party other than an applicant for recognition, which can choose when to submit its own application. Separately, the CFPB notes that an applicant may request that a pre-filing meeting, consistent with appendix A, be held before the effective date.

VI. CFPA Section 1022(b) Analysis

In developing this final rule, the CFPB has considered the potential benefits, costs, and impacts as required by section 1022(b)(2)(A) of the CFPA. Specifically, section 1022(b)(2)(A) of the CFPA requires the CFPB to consider the potential benefits and costs of a regulation to consumers and covered persons, including the potential reduction of access by consumers to consumer financial products or services, the impact on depository institutions and credit unions with \$10 billion or less in total assets as described in section 1026 of the CFPA, and the impact on consumers in rural areas. The Bureau consulted with appropriate prudential regulators and other Federal agencies regarding the consistency of this final rule with prudential, market, or systemic objectives administered by such agencies as required by section 1022(b)(2)(B) of the CFPA.¹⁵

This final rule creates an application and recognition process for industry standard setters but does not impose any compliance requirements based on the standards set by recognized standard setters. There are also no existing laws

or rules that reference such standards. The CFPB anticipates finalizing the proposed rule of which this current rule was a part. If such a future rule were to reference industry standards set by recognized standard setters in connection with compliance requirements, the impacts of such requirements would be attributed to and assessed as part of that rule. Absent such a future rule, the CFPB does not anticipate changes in industry standards attributable to this final rule. As a result, relative to the baseline of current law used for this analysis, this final rule does not have impacts on consumers or industry participants other than standard setters that choose to apply for recognition.

In response to the proposal, one industry commenter stated that additional guidelines for recognized standard setters should be published, including a full cost-benefit analysis. The analysis in this part reflects the full consideration of benefits and costs attributable to this final rule. As noted, only a limited number of provisions from the proposal are being finalized in this rule, none of which impose substantive compliance requirements. As a result, any analysis of the benefits and costs of substantive compliance requirements based on industry standards prior to the finalization of such requirements would be speculative and would not be accurate absent a future rule finalizing those provisions.

Impacts on Consumers

The CFPB does not anticipate changes in industry standards attributable to this final rule and, thus, no benefits or costs to consumers. The CFPB is finalizing this rule to ease compliance with potential future rulemakings.

Impacts on Covered Persons¹⁶

This final rule will impact standard setters that choose to apply for recognition. The CFPB expects such standard setters may incur costs associated with assembling and submitting application materials and responding to any follow up requests or clarifications in the application process. The submitted materials and follow up requests would differ across applicants, so the cost estimates in this analysis reflect an estimated average.

Standard setters may have members that are covered persons and members that are not covered persons. The CFPB

expects any costs incurred by standard setters would be spread across their membership.

Based on industry outreach and responses to the CFPB's proposed rule, few standard setters exist that maintain standards directly relevant to the Personal Financial Data Rights rule. As a result, the CFPB expects nine or fewer standard setters to apply for recognition.

Those standard setters that apply may incur an estimated \$10,604 in labor costs, on average. This estimate assumes 120 staff labor hours at an average total hourly compensation of \$88.37. This total hourly compensation reflects an average of May 2023 wages from the Bureau of Labor Statistics for compliance officers (\$38.55), lawyers (\$84.84), and general and operations managers (\$62.18), adjusted for non-wage compensation (30 percent of all compensation for private industry workers).¹⁷ If nine standard setters apply, the estimated total costs to industry would be \$95,436.

Consideration of Alternatives

The CFPB considered potential alternatives to this rule, including waiting to finalize provisions related to standard setter recognition until such time as substantive compliance requirements such as those in the full proposed rule were finalized.

In comments on the proposal related to standard setting, industry commenters generally noted that a lack of clarity on industry standards would make compliance with the proposal more costly and difficult. The comments indicated that having a standard setter recognized early relative to the compliance date for the proposal's substantive requirements could reduce industry costs. Based on these comments, the CFPB expects that the alternative of waiting to finalize the provisions in this final rule would have increased costs to industry of complying with any substantive compliance requirements finalized in a potential future rulemaking.

Potential Impacts on Depository Institutions and Credit Unions With \$10 Billion or Less in Total Assets, as Described in Section 1026

The only impacts attributable to this final rule on depository institutions and credit unions with \$10 billion or less in total assets would be through their roles

¹⁴ 5 U.S.C. 553(d). Because appendix A is not a substantive rule, appendix A is not subject to this requirement, but the CFPB is aligning its effective date with the effective date of §§ 1033.131 and 1033.141. *Id.*

¹⁵ Whether section 1022(b)(2)(A) and section 1022(b)(2)(B) are applicable to appendix A is unclear, but in order to inform the rulemaking more fully the Bureau performed the described analysis and consultations.

¹⁶ This analysis does not address whether or not standard setters satisfy the statutory definition of a covered person under the CFPA. 12 U.S.C. 5481(6). To the extent standard setters may not satisfy that standard, the CFPB elects to include them in its analysis.

¹⁷ These data reflect the mean hourly wages by occupation according to the 2023 Occupational Employment Statistics compiled by the Bureau of Labor Statistics. See U.S. Bureau of Labor Stat., U.S. Dep't of Labor, *Occupational Employment and Wages* (May 2023), https://www.bls.gov/oes/current/oes_stru.htm.

as members of standard setters that choose to apply for recognition. The CFPB expects these costs would be the same as the costs faced by any members of such standard setters, as described earlier in this part.

Potential Impacts on Consumers in Rural Areas, as Described in Section 1026

The CFPB does not anticipate changes in industry standards attributable to this final rule and, thus, no impacts on consumers in rural areas.

VII. Regulatory Flexibility Act Analysis

The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996, requires each agency to consider the potential impact of its regulations on small entities, including small businesses, small governmental units, and small not-for-profit organizations. The RFA defines a “small business” as a business that meets the size standard developed by the Small Business Administration pursuant to the Small Business Act.

The RFA generally requires an agency to conduct an initial regulatory flexibility analysis (IRFA) and a final regulatory flexibility analysis (FRFA) of any rule subject to notice-and-comment rulemaking requirements, unless the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. The Bureau also is subject to certain additional procedures under the RFA involving the convening of a panel to consult with small business representatives before proposing a rule for which an IRFA is required.

The CFPB convened a panel of small business representatives and conducted an IRFA as part of the proposal. However, this final rule includes only a limited number of provisions from that proposal, and none of the provisions being finalized impose significant compliance costs on small entities. As a result, the CFPB is not conducting a FRFA as part of this final rule. The CFPB would satisfy the requirements of the RFA by conducting a FRFA when it finalizes any provisions imposing significant compliance costs on small entities.

Some standard setters may be small entities, or may have members that are small entities. However, the CFPB expects nine or fewer standard setters to apply for recognition, which is not a substantial number of entities relative to all industry standard setters.

From a cost perspective, the CFPB expects any costs incurred by standard

setters to be spread across all members, including both small entities and larger entities. This implies per-member costs substantially lower than the \$10,604 in per-standard setter costs estimated above. Such costs will not be a significant economic impact on small entity members of standard setters.

Accordingly, the Director certifies that this final rule will not have a significant economic impact on a substantial number of small entities.

VIII. Paperwork Reduction Act

Under the Paperwork Reduction Act of 1995 (PRA), Federal agencies are generally required to seek, prior to implementation, approval from the Office of Management and Budget (OMB) for information collection requirements. Under the PRA, the Bureau may not conduct or sponsor, and, notwithstanding any other provision of law, a person is not required to respond to, an information collection unless the information collection displays a valid control number assigned by OMB.

The Bureau has determined that this final rule does not contain any new or substantively revised information collection requirements.

IX. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), the CFPB 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 the rule taking effect. The Office of Information and Regulatory Affairs has designated this rule as not a “major rule” as defined by 5 U.S.C. 804(2).

X. Severability

If any provision in §§ 1033.101, 1033.131, 1033.141, or appendix A, or any application of a provision, is stayed or determined to be invalid, the remaining provisions or applications are severable and shall continue in effect.

List of Subjects 12 CFR Part 1033

Banks, banking, Consumer protection, Credit, Credit unions, Electronic funds transfers, National banks, Privacy, Reporting and recordkeeping requirements, Savings associations, Voluntary standards.

Authority and Issuance

■ For the reasons set forth in the preamble, the CFPB adds 12 CFR part 1033, as follows:

PART 1033—PERSONAL FINANCIAL DATA RIGHTS

Subpart A—General

Sec.

1033.101 Authority, purpose, and organization.

1033.111 [Reserved].

1033.121 [Reserved].

1033.131 Definitions.

1033.141 Standard-setting bodies.

Subpart B—[Reserved]

Subpart C—[Reserved] Subpart D—[Reserved]

Appendix A—How To Apply for Recognition as a Standard Setter

Authority: 12 U.S.C. 5512; 12 U.S.C. 5514; 12 U.S.C. 5532; 12 U.S.C. 5533.

Subpart A—General

§ 1033.101 Authority, purpose, and organization.

(a) *Authority.* The regulation in this part is issued by the Consumer Financial Protection Bureau (CFPB) pursuant to the Consumer Financial Protection Act of 2010 (CFPA), Public Law 111–203, tit. X, 124 Stat. 1955.

(b) *Purpose.* This part implements the provisions of section 1033 of the CFPA, in part, by utilizing industry standards developed by standard-setting bodies recognized by the CFPB.

(c) *Organization.* This part is organized as follows:

(1) Subpart A establishes the authority, purpose, organization, and definitions applicable to this part, and is reserved for other purposes.

(2) Subpart B is reserved.

(3) Subpart C is reserved.

(4) Subpart D is reserved.

(5) Appendix A provides instructions for how a standard-setting body would apply for CFPB recognition.

§ 1033.111 [Reserved].

§ 1033.121 [Reserved].

§ 1033.131 Definitions.

For purposes of this part, the following definitions apply:

Consensus standard means a standard that is adopted by a recognized standard setter and that continues to be maintained by that recognized standard setter.

Recognized standard setter means a standard-setting body that has been recognized by the CFPB under § 1033.141.

§ 1033.141 Standard-setting bodies.

(a) *Recognition of a standard-setting body.* A standard-setting body may request CFPB recognition. Recognition will last up to five years, absent revocation. The CFPB will not recognize a standard-setting body unless it demonstrates that it satisfies the following attributes:

(1) *Openness:* The sources, procedures, and processes used are open to all interested parties, including: consumer and other public interest groups with expertise in consumer protection, financial services, community development, fair lending, and civil rights; authorized third parties; data providers; data recipients; data aggregators and other providers of services to authorized third parties; and relevant trade associations. Parties can meaningfully participate in standards development on a non-discriminatory basis.

(2) *Balance:* The decision-making power is balanced across all interested parties, including consumer and other public interest groups, and is reflected at all levels of the standard-setting body. There is meaningful representation for large and small commercial entities within these categories. No single interest or set of interests dominates decision-making. Achieving balance requires recognition that, even when a participant may play multiple roles, such as data provider and authorized third party, the weight of that participant's commercial concerns may align primarily with one set of interests. The ownership of participants is considered in achieving balance.

(3) *Due process and appeals:* The standard-setting body uses documented and publicly available policies and procedures, and it provides adequate notice of meetings and standards development, sufficient time to review drafts and prepare views and objections, access to views and objections of other participants, and a fair and impartial process for resolving conflicting views. An appeals process is available for the impartial handling of procedural appeals.

(4) *Consensus:* Standards development proceeds by consensus, which is defined as general agreement, though not necessarily unanimity. During the development of consensus, comments and objections are considered using fair, impartial, open, and transparent processes.

(5) *Transparency:* Procedures or processes for participating in standards development and for developing standards are transparent to participants and publicly available.

Subpart B—[Reserved]**Subpart C—[Reserved]****Subpart D—[Reserved]****Appendix A to Part 1033—Personal Financial Data Rights Rule: How To Apply for Recognition as a Standard Setter**

If you want the CFPB to designate your organization as a recognized standard setter, you should follow the steps described below.

We may amend this process from time to time.

Step One: Requesting Recognition

Submit a written request for recognition.¹

This should include key contact information, evidence of your organization's policies and practices,² and an explanation of how your organization satisfies each of the requirements in the Personal Financial Data Rights rule to be a recognized standard setter.³ Your request should also describe how current and/or anticipated standards issued by your organization relate to open banking.

In advance of filing your request, you can seek a pre-filing meeting with us. We can walk you through the application process and help you make a complete submission.

Send formal submissions, as well as requests for pre-filing meetings, to: openbankingstandards@cfpb.gov.

Step Two: Additional Information and Public Comment

After reviewing your submission, we may request additional information to ensure that your application is complete.

We may publish your application.

We may also seek public input on your application and invite your responses to any information we receive on that basis.

Step Three: Our Review

When reviewing your application, we consider whether your policies and practices meet all the requirements for recognition. We also evaluate whether your application is accurate and complete.

We prioritize and review applications based on the extent to which recognizing your organization helps us to implement open banking.⁴

Step Four: Application Decision

CFPB recognition will be publicly disclosed on our website, along with the

¹ Sensitive personal information should not be provided.

² Evidence may include (but is not limited to) charters, bylaws, policies, procedures, fee schedules, meeting minutes, membership lists, financial statements/disclosures, publicly available materials, and issued standards.

³ Relevant legal requirements are described at 12 CFR 1033.141. When explaining how your organization meets these requirements, you should reference relevant elements of the evidence you submit in support of your application.

⁴ Section 1033 of the Consumer Financial Protection Act, 12 U.S.C. 5533, describes the CFPB's role in implementing open banking.

applicable terms and conditions of such recognition, such as its duration.

If the CFPB declines to recognize your organization, we will notify you.

You may withdraw your application at any time or for any reason.

If we determine that your organization is close to meeting, but does not yet meet, the requirements for CFPB recognition, we may ask you to provide a written plan specifying how and when you will take the steps required for full recognition. If that plan is satisfactory, we may state on our website that your organization has received contingent recognition. Once you provide us with evidence that you have successfully executed on that plan (or otherwise addressed the relevant contingencies), the CFPB may extend full recognition.

Step Five: Recognition

There are several points to keep in mind about recognition.

As a recognized standard setter, you agree that the CFPB may monitor your organization and that you will provide information that we request.

You must also provide us, within 10 days, written explanation of any material change to information that was submitted with your application or during recognition, as well as any reason your organization may no longer meet underlying requirements for recognition.

In addition, you must meet any other specified terms and conditions of your recognition, which may include our reserving the right to observe or participate in standard setting.

If your recognition is set to expire, you can apply for re-recognition by re-starting at Step One at least 180 days before expiration. We may temporarily extend your recognition while we consider your request for re-recognition.

We may modify or revoke your recognition. The CFPB expects to notify you of the reasons it intends to revoke or modify recognition, and to provide your organization with an opportunity to address the CFPB's concerns.

Rohit Chopra,

Director, Consumer Financial Protection Bureau.

[FR Doc. 2024-12658 Filed 6-10-24; 8:45 am]

BILLING CODE 4810-am-P

DEPARTMENT OF TRANSPORTATION**Federal Aviation Administration****14 CFR Part 39**

[Docket No. FAA-2024-0234; Project Identifier MCAI-2023-01215-A; Amendment 39-22742; AD 2024-08-09]

RIN 2120-AA64

Airworthiness Directives; GA8 Airvan (Pty) Ltd Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The FAA is adopting a new airworthiness directive (AD) for certain GA8 Airvan (Pty) Ltd Model GA8 and GA8-TC320 airplanes. This AD is prompted by reports of insufficient electrical bonding of the solenoid (relay) box assembly that could result in degraded performance, errors, or intermittent failures of equipment connected to electrical Bus 1, Bus 2, associated electrical control, and protective devices fitted within or attached to the solenoid box. This AD requires inspecting for an existing wire connecting the relay box earth point to the ground power socket, and if one is not present, installing a mechanical connection. The FAA is issuing this AD to address the unsafe condition on these products.

DATES: This AD is effective July 16, 2024.

The Director of the Federal Register approved the incorporation by reference of a certain publication listed in this AD as of July 16, 2024.

ADDRESSES:

AD Docket: You may examine the AD docket at *regulations.gov* under Docket No. FAA-2024-0234; or in person at Docket Operations between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this final rule, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The address for Docket Operations is U.S. Department of Transportation, Docket Operations, M-30, West Building Ground Floor, Room W12-140, 1200 New Jersey Avenue SE, Washington, DC 20590.

Material Incorporated by Reference:

- For service information, contact GA8 Airvan (Pty) Ltd, GippsAero Technical Services, P.O. Box 881, Morwell, Victoria 3840, Australia; phone: +61 (0)3 5172 1200; email: *TECHPUBS@gippsaero.com.au*; website: *gippsaero.com.au*.

- You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 901 Locust, Kansas City, MO 64106. For information on the availability of this material at the FAA, call (817) 222-5110. It is also available at *regulations.gov* under Docket No. FAA-2024-0234.

FOR FURTHER INFORMATION CONTACT:

Doug Rudolph, Aviation Safety Engineer, FAA, 1600 Stewart Avenue,

Suite 410, Westbury, NY 11590; phone: (816) 329-4059; email: *doug.rudolph@faa.gov*.

SUPPLEMENTARY INFORMATION:

Background

The FAA issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 by adding an AD that would apply to certain GA8 Airvan (Pty) Ltd Model GA8 and GA8-TC320 airplanes. The NPRM published in the **Federal Register** on February 23, 2024 (89 FR 13620). The NPRM was prompted by AD GA8/11, dated November 21, 2023 (also referred to as the MCAI), issued by Civil Aviation Safety Authority, which is the aviation authority for Australia. The MCAI states that operators made two reports and a few anecdotal reports of intermittent system discrepancies attributed to insufficient electrical bonding of the solenoid (relay) box assembly. Without a dedicated solenoid box electrical bonding connection, these airplanes may suffer degraded performance, errors, or intermittent failures of equipment connected to electrical Bus 1, Bus 2, associated electrical control, and protective devices fitted within or attached to the solenoid box. The majority of Model GA8 and GA8-TC320 airplanes were produced with the relay box electrically bonded to the airframe via the relay box lid and the hardware (screws) holding it in place. The relay box did not have a dedicated bonding point or mechanical connection.

The MCAI requires doing the actions specified in GippsAero Service Bulletin SB-GA8-2023-216, Issue 1, dated February 24, 2023 (GippsAero SB-GA8-2023-216, Issue 1). These actions include inspecting for an existing wire connecting the relay box earth point to the ground power socket, and if one is not present, installing a mechanical connection.

In the NPRM, the FAA proposed to require inspecting for an existing wire connecting the relay box earth point to the ground power socket, and if one is not present, installing a mechanical connection. The FAA is issuing this AD to address the unsafe condition on these products.

You may examine the MCAI in the AD docket at *regulations.gov* under Docket No. FAA-2024-0234.

Discussion of Final Airworthiness Directive

Comments

The FAA received no comments on the NPRM or on the determination of the costs.

Conclusion

These products have been approved by the aviation authority of another country and are approved for operation in the United States. Pursuant to the FAA's bilateral agreement with this State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI referenced above. The FAA reviewed the relevant data and determined that air safety requires adopting this AD as proposed. Accordingly, the FAA is issuing this AD to address the unsafe condition on these products. This AD is adopted as proposed in the NPRM.

Related Service Information Under 1 CFR Part 51

The FAA reviewed GippsAero SB-GA8-2023-216, Issue 1. This service information specifies procedures for inspecting for an existing wire connecting the relay box earth point to the ground power socket, and if one is not present, installing a mechanical connection.

This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in **ADDRESSES**.

Differences Between This AD and the MCAI

The MCAI applicability is Gippsland Aeronautics Model GA8 Series airplanes. The applicability in this AD are GA8 Airvan (Pty) Ltd Model GA8 and GA8-TC320 airplanes because that is what is on the FAA type certificate.

Part A, step 4. of the Accomplishment Instructions in GippsAero SB-GA8-2023-216, Issue 1, specifies to proceed to the Documentation section to update the airplane logbook, but that action is not specifically required by this AD as current FAA regulations already require a logbook entry for compliance with AD actions.

Costs of Compliance

The FAA estimates that this AD affects 62 airplanes of U.S. registry.

The FAA estimates the following costs to comply with this AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Inspect for mechanical connection	1 work-hour × \$85 per hour = \$85	\$0	\$85	\$5,270

The FAA estimates the following costs to do any necessary actions that

would be required based on the results of the inspection. The agency has no

way of determining the number of airplanes that might need these actions:

ON-CONDITION COSTS

Action	Labor cost	Parts cost	Cost per product
Install mechanical connection	1 work-hour × \$85 per hour = \$85	\$170	\$255

The FAA has included all known costs in its cost estimate. According to the manufacturer, however, some of the costs of this AD may be covered under warranty, thereby reducing the cost impact on affected operators.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

The FAA is issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: General requirements. Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

This AD will not have federalism implications under Executive Order 13132. This AD will not have 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.

For the reasons discussed above, I certify that this AD:

- (1) Is not a "significant regulatory action" under Executive Order 12866,
- (2) Will not affect intrastate aviation in Alaska, and
- (3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities

under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

- 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

- 2. The FAA amends § 39.13 by adding the following new airworthiness directive:

2024-08-09 GA 8 Airvan (Pty) Ltd:
Amendment 39-22742; Docket No. FAA-2024-0234; Project Identifier MCAI-2023-01215-A.

(a) Effective Date

This airworthiness directive (AD) is effective July 16, 2024.

(b) Affected ADs

None.

(c) Applicability

This AD applies to GA8 Airvan (Pty) Ltd Model GA8 airplanes, all serial numbers up to and including GA8-20-262; and Model GA8-TC320 airplanes, all serial numbers up to and including GA8-TC 320-20-261; certificated in any category.

(d) Subject

Joint Aircraft System Component (JASC) Code 2497, Electrical Power System Wiring.

(e) Unsafe Condition

This AD was prompted by reports of insufficient electrical bonding of the solenoid (relay) box assembly. The FAA is issuing this AD to address possible missing mechanical

connections. The unsafe condition, if not addressed, could result in degraded electrical equipment performance, errors, or intermittent failures of equipment connected to electrical Bus 1, Bus 2, associated electrical control and protective devices fitted within or attached to the solenoid box, which could lead to loss of equipment essential for safe flight.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Required Actions

(1) Within 100 hours time-in-service (TIS) after the effective date of this AD, inspect for a mechanical connection between the relay box earth point to the ground power socket in accordance with Part A, steps 1. through 4. of the Accomplishment Instructions in GippsAero Service Bulletin SB-GA8-2023-216, Issue 1, dated February 24, 2023 (GippsAero SB-GA8-2023-216, Issue 1), except where step 4. specifies to proceed to the Documentation section to update the airplane logbook, that action is not specifically required by this AD.

(2) If no mechanical connection between the relay box earth point to the ground power socket is found during the inspection required by paragraph (g)(1) of this AD, before further flight, install a mechanical connection in accordance with Part B, steps 1. through 3. of the Accomplishment Instructions in GippsAero SB-GA8-2023-216, Issue 1.

(h) Alternative Methods of Compliance (AMOCs)

The Manager, International Validation Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or local Flight Standards District Office, as appropriate. If sending information directly to the manager of the International Validation Branch, mail it to the address identified in paragraph (i) of this AD or email to: 9-AVS-AIR-730-AMOC@faa.gov. If mailing information, also submit information by email. Before using any approved AMOC, notify your appropriate principal inspector,

or lacking a principal inspector, the manager of the local Flight Standards District Office/certificate holding district office.

(i) Additional Information

For more information about this AD, contact Doug Rudolph, Aviation Safety Engineer, FAA, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; phone: (816) 329-4059; email: doug.rudolph@faa.gov.

(j) Material Incorporated by Reference

(1) The Director of the Federal Register approved the incorporation by reference of the service information listed in this paragraph under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) You must use this service information as applicable to do the actions required by this AD, unless the AD specifies otherwise.

(i) GippsAero Service Bulletin SB-GA8-2023-216, Issue 1, dated February 24, 2023.

Note 1 to paragraph (j)(2)(i): The date on the first page of this document is February 24, 2023, and the date on the subsequent pages is February 25, 2023.

(ii) [Reserved]

(3) For service information identified in this AD, contact GA8 Airvan (Pty) Ltd, GippsAero Technical Services, P.O. Box 881, Morwell, Victoria 3840, Australia; phone: +61 (0)3 5172 1200; email: TECHPUBS@gippsaero.com.au; website: gippsaero.com.au.

(4) You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 901 Locust, Kansas City, MO 64106. For information on the availability of this material at the FAA, call (817) 222-5110.

(5) You may view this material at the National Archives and Records Administration (NARA). 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.

Issued on May 22, 2024.

James D. Foltz,

Deputy Director, Compliance & Airworthiness Division, Aircraft Certification Service.

[FR Doc. 2024-12588 Filed 6-10-24; 8:45 am]

BILLING CODE 4910-13-P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA-2024-0041; Project Identifier AD-2024-00032-E; Amendment 39-22764; AD 2024-11-03]

RIN 2120-AA64

Airworthiness Directives; International Aero Engines, AG Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The FAA is adopting a new airworthiness directive (AD) for certain

International Aero Engines, AG (IAE AG) Model V2500 engines. This AD was prompted by an analysis of an event involving an International Aero Engines, LLC (IAE LLC) Model PW1127GA-JM engine, which experienced a high-pressure compressor (HPC) 7th-stage integrally bladed rotor (IBR-7) separation that resulted in an aborted takeoff. This AD requires performing an angled ultrasonic inspection (AUSI) of certain high-pressure turbine (HPT) 1st-stage hubs and HPT 2nd-stage hubs for cracks and replacing if necessary. This AD also requires accelerated replacement of certain HPT 1st-stage hubs and HPT 2nd-stage hubs. The FAA is issuing this AD to address the unsafe condition on these products.

DATES: This AD is effective June 26, 2024.

The Director of the Federal Register approved the incorporation by reference of certain publications listed in this AD as of June 26, 2024.

ADDRESSES:

AD Docket: You may examine the AD docket at regulations.gov under Docket No. FAA-2024-0041; or in person at Docket Operations between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this final rule, any comments received, and other information. The address for Docket Operations is U.S. Department of Transportation, Docket Operations, M-30, West Building Ground Floor, Room W12-140, 1200 New Jersey Avenue SE, Washington, DC 20590.

Material Incorporated by Reference:

- For service information, contact International Aero Engines, AG, 400 Main Street, East Hartford, CT 06118; phone: (860) 565-0140; email: help24@pw.utc.com; website: connect.prattwhitney.com.

- You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 1200 District Avenue, Burlington, MA 01803. For information on the availability of this material at the FAA, call (817) 222-5110.

FOR FURTHER INFORMATION CONTACT:

Carol Nguyen, Aviation Safety Engineer, FAA, 2200 South 216th Street, Des Moines, WA 98198; phone: (781) 238-7655; email: carol.nguyen@faa.gov.

SUPPLEMENTARY INFORMATION:

Background

The FAA issued a notice of proposed rulemaking (NPRM) to amend 14 CFR part 39 by adding an AD that would apply to certain IAE AG Model V2500 engines. The NPRM published in the **Federal Register** on February 5, 2024

(89 FR 7636). The NPRM was prompted by an event on December 24, 2022, when an Airbus Model A320neo airplane, powered by IAE LLC Model PW1127GA-JM engines, experienced a failure of the HPC IBR-7 that resulted in an engine shutdown and aborted take-off. Following this event, the manufacturer conducted a records review of production and field-returned parts and re-evaluated their engineering analysis methodology. The new analysis found that the failure of the HPC IBR-7 was caused by a nickel powdered metal anomaly, similar in nature to an anomaly previously observed on March 18, 2020, when an Airbus Model A321-231 airplane, powered by IAE AG Model V2533-A5 engines, experienced an uncontained HPT 1st-stage hub failure that resulted in high-energy debris penetrating the engine cowling. The analysis also concluded that there is an increased risk of failure for a subpopulation of HPT 1st-stage hubs and HPT 2nd-stage hubs that were manufactured from the same production campaign (a batch of nickel powdered metal) as the HPT 1st-stage hub that failed on March 18, 2020; these parts have a higher likelihood of containing the nickel powdered metal anomaly and are susceptible to failure much earlier than previously determined. In the NPRM, the FAA proposed to require performing an AUSI of certain HPT 1st-stage hubs and HPT 2nd-stage hubs and, depending on the results of the inspections, replacing the HPT 1st-stage hubs or HPT 2nd-stage hubs. The FAA also proposed to require accelerated replacement of certain HPT 1st-stage hubs and HPT 2nd-stage hubs. The FAA is issuing this AD to address the unsafe condition on these products.

Discussion of Final Airworthiness Directive

Comments

The FAA received comments from 14 commenters, including the Air Line Pilots Association, International (ALPA); JetBlue Airways (JetBlue); Lufthansa Technik AG (Lufthansa); MTU Maintenance Hannover GmbH; MTU Maintenance Zhuhai Co. Ltd; Pratt & Whitney (PW); Turkish Engine Center (TEC); United Airlines; five anonymous commenters; and an individual commenter. ALPA, United Airlines, the individual commenter, and one anonymous commenter supported the proposed AD without change. Ten commenters requested changes to the proposed AD. The following presents the comments received on the NPRM and the FAA's response to each comment.

Request To Clarify Affected Parts

Two anonymous commenters requested that the FAA clarify if HPT hubs that were produced before 2020 are part of the affected subpopulation if they were installed in January of 2019 or February of 2019 and had not accumulated more than 1,200 flight cycles (FCs).

The FAA clarifies that the affected population was manufactured from the same production campaign (a batch of nickel powdered metal) as the HPT 1st-stage hub that failed on March 18, 2020. The FAA notes that those affected parts are defined by serial number within the service information documents that are incorporated by reference in this AD. The FAA did not change this AD as a result of these comments.

Request To Clarify AUSI for Parts Removed From Service

An anonymous commenter requested that the FAA change the proposed AD to clarify if removal of the affected part from service and replacement with a part eligible for installation is an acceptable alternative to performing the AUSI required by paragraph (g)(1) of the proposed AD. The commenter noted that affected parts may be proactively replaced or found unserviceable before the AUSI is required.

The FAA disagrees with the request to change the AD because the AUSI required by paragraph (g)(1) of the proposed AD only applies to “affected parts.” If the part has been replaced with a part “eligible for installation,” then it is not an “affected part” and the AUSI is not required. The FAA did not change this AD as a result of this comment.

Request To Clarify Start Date for FC Accumulation

An anonymous commenter requested that the FAA clarify the point or date from which FCs should be counted in order to remain compliant with the proposed AD. The commenter noted that in Table 1 to Paragraph (g)(1) of the proposed AD, the AUSI compliance times are specified in terms of FCs, and for the HPT 1st-stage hub with Part Number (P/N) 2A5001, the compliance requirement is based on 100 FCs from a specific reference point.

The FAA clarifies that the FC count for AUSI compliance times begins on the effective date of this AD. The FAA has also changed the fourth column header of Table 1 to Paragraph (g)(1), Table 2 to Paragraph (g)(4), and Table 3 to Paragraph (g)(5) of this AD to read as follows: “Flight cycle (FC) limit from the effective date of this AD.”

Request To Account for Inability To Obtain Special Instruction

JetBlue requested that the FAA do one of the following:

(1) remove the reference to PW Special Instruction No. 189F–23, dated November 20, 2023 (PW SI No. 189F–23), from the effectivity of the affected parts listed in Table 1 to Paragraph (g)(1) and Table 2 to Paragraph (g)(4) of this AD; or

(2) have IAE LLC revise IAE AG Non-Modification Service Bulletin (NMSB) V2500–ENG–72–0720, dated November 20, 2023 (V2500–ENG–72–0720) to provide the list of the affected P/Ns and serial numbers of the hubs mentioned in PW SI No. 189F–23; or

(3) list all affected hubs within the AD.

JetBlue noted that they were unable to obtain PW SI No. 189F–23 from IAE LLC because it relates to a military program and there are concerns about the inadvertent release of data.

The FAA disagrees with the request because PW SI No. 189F–23 applies to the V2531–E5 engine model only, and therefore IAE only provides PW SI No. 189F–23 to those owning or operating the product. The FAA notes that material that is incorporated by reference in airworthiness directives can be accessed by the means identified in the ADDRESSES section. For clarity, the FAA added the phrase “which only applies to the IAE AG V2531–E5 Model engine” at the end of each reference to the service bulletin, except for paragraph (l), Material Incorporated by Reference, of the final rule.

Request To Adjust Compliance Times

JetBlue requested that the FAA adjust the compliance times for Table 1 to Paragraph (g)(1), Table 2 to Paragraph (g)(4), and Table 3 to Paragraph (g)(5) of this AD to match the drawdown period of IAE AG NMSB V2500–ENG–72–0720. JetBlue noted that IAE AG NMSB V2500–ENG–72–0720 provides an additional 200 FCs and is based on an effective date of January 1, 2024, while the proposed AD provides 200 FCs less and is based on the effective date of the AD. JetBlue also noted that it planned the engine removal schedule based on the drawdown of IAE AG NMSB V2500–ENG–72–0720, including working with the engine shops for induction slots and spare engines (including obtaining lease engines).

The FAA disagrees with the request because the drawdown times for IAE AG NMSB V2500–ENG–72–0720 started on January 1, 2024, and the FAA reduced the compliance time for the AUSIs required by this AD in order to better

align with the control program. The FAA did not change this AD as a result of this comment.

Comment Regarding Low Cost Estimate

JetBlue commented that the estimated cost of compliance provided in the proposed AD is not realistic and would be only achievable for a new engine or engine just returning to the shop. JetBlue also noted that the estimated cost would have great financial impact on operators, and the manufacturer is not providing a support program to address this.

The FAA disagrees that the estimated cost in the AD is unrealistic. The FAA based its estimated cost of compliance on the work-hours and parts costs from the manufacturer to perform the required actions. The commenter did not provide specifics on which cost estimates were incorrect and what would be considered realistic. The FAA did not change this AD as a result of this comment.

Comment Regarding Parts Eligible for Installation

Lufthansa commented that parts considered eligible for installation should not be limited to the disk S/Ns that are not listed in V2500–ENG–72–0720 or PW SI No. 189F–23. Lufthansa noted that disk S/Ns listed in those documents that have passed AUSI are also eligible for installation and need to be removed within 4,000 FCs from accomplishment of the AUSI or at the next HPT module removal after the AUSI.

The FAA agrees to change paragraph (h)(1) of this AD to include parts that were not removed from service as a result of the required actions of this AD as “parts eligible for installation.”

Request To Redefine AUSI Inspected Part Installation Date

TEC requested that the FAA change the definition of the date that an AUSI inspected part was installed in paragraph (h)(5) of the proposed AD from “the date of the authorized release certification for the shop visit at which the part was first installed after the AUSI was performed” to “the HPT hub release certificate date.” TEC noted that it is possible for two HPT hubs to be inspected on the same date and be installed on different engines. Since release dates of these engines can differ, it is possible for different replacement compliance times to apply to parts that were inspected on the same day.

The FAA disagrees with the request to change the definition of the date that an AUSI inspected part was installed. The FAA acknowledges that AUSI

compliance times will vary depending on when the AUSI inspected part was installed, and this was taken into consideration in order to manage shop visit capacity. The FAA did not change this AD as a result of this comment.

Request To Revise Paragraph (g)(1) of the Proposed AD

MTU Maintenance Hannover GmbH and PW requested that the FAA revise paragraph (g)(1) of the proposed AD to remove mention of AUSI inspected parts installed on or after November 1, 2023. MTU Maintenance Hannover GmbH requested that the phrase “or the AUSI inspected part was installed on or after November 1, 2023” be removed from paragraph (g)(1) of the proposed AD entirely, and PW requested that the FAA change the language from “or the AUSI inspected part was installed on or after November 1, 2023” to “before November 1, 2023.” JetBlue, MTU Maintenance Hannover GmbH, and PW all noted that the current language in paragraph (g)(1) of the proposed AD could cause an early engine removal by requiring a second AUSI inspection on hubs that had been previously AUSI inspected.

The FAA agrees to revise paragraph (g)(1) of this AD to prevent the potential requirement of performing a second AUSI on hubs that had an AUSI performed on or after November 1, 2023.

Request To Revise Paragraph (g)(2) of the AD

MTU Maintenance Hannover GmbH and PW requested that the FAA revise paragraph (g)(2) of the proposed AD to clarify the required actions for engines with AUSI inspected parts that were installed on or after November 1, 2023. MTU Maintenance Hannover GmbH requested that the FAA revise paragraph (g)(2) to read as follows: “For engines with an AUSI inspected part installed on or after November 1, 2023 or for parts inspected in accordance with paragraph (g)(1) of this AD, within 4,000 FCs from accomplishment of the AUSI required by paragraph (g)(1) of this AD or at the next HPT module removal after the AUSI required by paragraph (g)(1) of this AD, whichever occurs first, remove the part from service and replace with a part eligible for installation.” PW requested that the FAA revise paragraph (g)(2) of the proposed AD to read as follows: “For parts inspected in accordance with paragraph (g)(1) of this AD, or for parts previously AUSI inspected and installed on or after November 1, 2023, within 4,000 FCs from accomplishment of the AUSI

required by paragraph (g)(1) of this AD or at the next HPT module removal after the AUSI required by paragraph (g)(1) of this AD, whichever occurs first, remove the part from service and replace with a part eligible for installation.” PW noted that the intent is to inspect everything, and any part inspected after November 1, 2023 will be removed at 4,000 FCs.

The FAA agrees to revise paragraph (g)(2) of this AD to clarify the required actions for engines with AUSI inspected parts that were installed on or after November 1, 2023.

Request To Clarify Compliance Time for High-Thrust Engines

MTU Maintenance Zhuhai Co. Ltd requested that the FAA clarify the part replacement compliance time in Table 2 to Paragraph (g)(4) of the proposed AD for a part not previously operated in a high-thrust engine model that has its engine rating changed to a high-thrust rating without any disassembly or removal of the HPT module.

The FAA clarifies that after the initial flight in the newly rated high-thrust engine, the part is considered to have previously operated in a high-thrust engine and it will be required to use the lower cycle limits. For example, the HPT 1st-stage hub will need to be removed at 1,800 FCs after the effective date of the AD because it is now operating in a high-thrust engine. The FAA notes that the removal or non-removal of the HPT module at shop visit would not have an effect on this scenario as these are considered the new replacement cycle limits for the affected parts on the effective date of the AD. The FAA has revised paragraph (h)(3) of this AD by removing the second instance of the word “previously” from the definition in order to avoid potential misinterpretation.

Conclusion

The FAA reviewed the relevant data, considered any comments received, and determined that air safety requires adopting this AD as proposed. Accordingly, the FAA is issuing this AD to address the unsafe condition on these products. Except for minor editorial changes, and any other changes described previously, this AD is adopted as proposed in the NPRM. None of the changes will increase the economic burden on any operator.

Related Service Information Under 1 CFR Part 51

The FAA reviewed IAE AG NMSB V2500–ENG–72–0720, dated November

20, 2023; and PW Special Instruction No. 189F–23, dated November 20, 2023, which only applies to the IAE AG V2531–E5 Model engine. This service information specifies procedures for performing an AUSI for cracks on affected HPT 1st-stage hubs and HPT 2nd-stage hubs. This service information also specifies the list of affected HPT 1st-stage hubs and HPT 2nd-stage hubs, identified by part number and serial number, installed on certain IAE AG engines. This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in the **ADDRESSES** section.

Interim Action

The FAA considers this AD to be an interim action. The unsafe condition is still under investigation by the manufacturer and, depending on the results of that investigation, the FAA may consider further rulemaking action.

Justification for Determination of the Effective Date

Section 553(d) of the Administrative Procedure Act (APA) (5 U.S.C. 551 *et seq.*) authorizes agencies to make rules effective in less than thirty days, upon a finding of “good cause.” The FAA has found that the risk to the flying public justifies a shortened effective date for this rule due to powdered metal anomalies in HPT 1st-stage hubs and HPT 2nd-stage hubs that could lead to premature fracture and uncontained failure, which could lead to the release of high-energy debris, damage to the engine, damage to the airplane, and loss of the airplane. The longer these parts remain in service, the higher the probability of failure. Accordingly, the FAA finds that good cause exists pursuant to 5 U.S.C. 553(d) for making this amendment effective in less than 30 days.

Costs of Compliance

The FAA estimates that this AD affects 116 engines installed on airplanes of U.S. registry. The FAA estimates that 40 engines need an AUSI of the HPT 1st-stage hub; 40 engines need an AUSI of the HPT 2nd-stage hub; 67 engines need replacement of the HPT 1st-stage hub; and 49 engines need replacement of the HPT 2nd-stage hub.

The FAA estimates the following costs to comply with this AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
AUSI of HPT 1st-stage hub	5 work-hours × \$85 per hour = \$425	\$0	\$425	\$17,000
AUSI of HPT 2nd-stage hub	5 work-hours × \$85 per hour = \$8,500	0	425	17,000
Replace HPT 1st-stage hub	100 work-hours × \$85 per hour = \$8,500	460,000	468,500	31,389,500
Replace HPT 2nd-stage hub	100 work-hours × \$85 per hour = \$8,500	360,000	368,500	18,056,500

The FAA has included all known costs in its cost estimate. According to the manufacturer, however, some of the costs of this AD may be covered under warranty, thereby reducing the cost impact on affected operators.

Authority for This Rulemaking

Title 49 of the United States Code specifies the FAA's authority to issue rules on aviation safety. Subtitle I, section 106, describes the authority of the FAA Administrator. Subtitle VII: Aviation Programs, describes in more detail the scope of the Agency's authority.

The FAA is issuing this rulemaking under the authority described in Subtitle VII, Part A, Subpart III, Section 44701: General requirements. Under that section, Congress charges the FAA with promoting safe flight of civil aircraft in air commerce by prescribing regulations for practices, methods, and procedures the Administrator finds necessary for safety in air commerce. This regulation is within the scope of that authority because it addresses an unsafe condition that is likely to exist or develop on products identified in this rulemaking action.

Regulatory Findings

This AD will not have federalism implications under Executive Order 13132. This AD will not have 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.

For the reasons discussed above, I certify that this AD:

(1) Is not a "significant regulatory action" under Executive Order 12866,

(2) Will not affect intrastate aviation in Alaska, and

(3) Will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA amends 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

■ 1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new airworthiness directive:

2024–11–03 International Aero Engines, AG: Amendment 39–22764; Docket No. FAA–2024–0041; Project Identifier AD–2024–00032–E.

(a) Effective Date

This airworthiness directive (AD) is effective June 26, 2024.

(b) Affected ADs

This AD is related to AD 2022–02–09, Amendment 39–21906 (87 FR 7029, February 8, 2022) (AD 2022–02–09).

(c) Applicability

This AD applies to International Aero Engines, AG (IAE AG) Model V2522–A5, V2524–A5, V2525–D5, V2527–A5, V2527E–A5, V2527M–A5, V2528–D5, V2530–A5, V2531–E5, and V2533–A5 engines.

(d) Subject

Joint Aircraft System Component (JASC) Code 7230, Turbine Engine.

(e) Unsafe Condition

This AD was prompted by an analysis of an event involving an International Aero Engines, LLC Model PW1127GA–JM engine, which experienced failure of a high-pressure compressor 7th-stage integrally bladed rotor that resulted in an engine shutdown and aborted takeoff. The FAA is issuing this AD to prevent failure of the high-pressure turbine (HPT) 1st-stage hub and HPT 2nd-stage hub. The unsafe condition, if not addressed, could result in uncontained hub failure, release of high-energy debris, damage to the engine, damage to the airplane, and loss of the airplane.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Required Actions

(1) For engines with an installed part, part number (P/N), and serial number (S/N) listed in Table 1 to paragraph (g)(1) of this AD, with no angled ultrasonic inspection (AUSI) performed, at the next engine shop visit after the effective date of this AD before exceeding the applicable cycle limit specified in Table 1 to paragraph (g)(1) of this AD, perform an AUSI of the affected parts for cracks in accordance with the applicable service information listed in Table 1 to paragraph (g)(1) of this AD.

TABLE 1 TO PARAGRAPH (g)(1)—AUSI COMPLIANCE TIMES

Part	Table S/N is listed in	Previously operated in high-thrust model engine	Flight cycle (FC) limit from the effective date of this AD	Applicable service information (see paragraph (l)(2) of this AD)
HPT 1st-stage hub P/N 2A5001.	Table 1 of IAE AG Non-Modification Service Bulletin V2500–ENG–72–0720, dated November 20, 2023 (IAE AG NMSB V2500–ENG–72–0720).	Yes	100 FCs	Accomplishment Instructions, paragraph 5., of IAE AG NMSB V2500–ENG–72–0720.
HPT 1st-stage hub P/N 2A5001.	Table 1 of Pratt & Whitney (PW) Special Instruction No. 189F–23, dated November 20, 2023 (PW SI No. 189F–23), which only applies to the IAE AG V2531–E5 Model engine.	Yes	100 FCs	Accomplishment Instructions, paragraph 5., of PW SI No. 189F–23, which only applies to the IAE AG V2531–E5 Model engine.
HPT 1st-stage hub P/N 2A5001.	Table 1 of IAE AG NMSB V2500–ENG–72–0720.	No	700 FCs	Accomplishment Instructions, paragraph 5., of IAE AG NMSB V2500–ENG–72–0720.
HPT 2nd-stage hub P/N 2A4802.	Table 2 of IAE AG NMSB V2500–ENG–72–0720.	Yes	800 FCs	Accomplishment Instructions, paragraph 6., of IAE AG NMSB V2500–ENG–72–0720.
HPT 2nd-stage hub P/N 2A4802.	Table 2 PW SI No. 189F–23, which only applies to the IAE AG V2531–E5 Model engine.	Yes	800 FCs	Accomplishment Instructions, paragraph 6., of PW SI No. 189F–23, which only applies to the IAE AG V2531–E5 Model engine.
HPT 2nd-stage hub P/N 2A4802.	Table 2 of IAE AG NMSB V2500–ENG–72–0720.	No	1100 FCs	Accomplishment Instructions, paragraph 6., of IAE AG NMSB V2500–ENG–72–0720.

(2) For parts inspected in accordance with paragraph (g)(1) of this AD, or for AUSI inspected parts installed on or after November 1, 2023, within 4,000 FCs from accomplishment of the AUSI or at the next HPT module removal after the AUSI, whichever occurs first, remove the part from service and replace with a part eligible for installation.

(3) If any crack is found during the inspections required by paragraphs (g)(1) of this AD, before further flight, remove the affected part from service and replace with a part eligible for installation.

(4) For engines with an AUSI inspected part installed prior to November 1, 2023, having a P/N and S/N listed in Table 2 to paragraph (g)(4) of this AD, at the next HPT

module removal after the effective date of this AD, but before exceeding the applicable cycle limit specified in Table 2 to paragraph (g)(4) of this AD, remove the affected part from service and replace with a part eligible for installation.

TABLE 2 TO PARAGRAPH (g)(4)—PART REPLACEMENT COMPLIANCE TIMES

Part	Table S/N is listed in	Previously operated in high-thrust model engine	Flight cycle limit from the effective date of this AD
HPT 1st-stage hub P/N 2A5001.	Table 1 of IAE AG NMSB V2500–ENG–72–0720	Yes	1,800 FCs.
HPT 1st-stage hub P/N 2A5001.	Table 1 of PW SI No. 189F–23, which only applies to the IAE AG V2531–E5 Model engine.	Yes	1,800 FCs.
HPT 1st-stage hub P/N 2A5001.	Table 1 of IAE AG NMSB V2500–ENG–72–0720	No	2,800 FCs.
HPT 2nd-stage hub P/N 2A4802.	Table 2 of IAE AG NMSB V2500–ENG–72–0720	Yes	3,400 FCs.
HPT 2nd-stage hub P/N 2A4802.	Table 2 of PW SI No. 189F–23, which only applies to the IAE AG V2531–E5 Model engine.	Yes	3,400 FCs.
HPT 2nd-stage hub P/N 2A4802.	Table 2 of IAE AG NMSB V2500–ENG–72–0720	No	3,800 FCs.

(5) For engines with an installed part that has a P/N and S/N listed in Table 3 to paragraph (g)(5) of this AD, at the next HPT module removal after the effective date of

this AD, but before exceeding the applicable cycle limit specified in Table 3 to paragraph (g)(5) of this AD, remove the affected part

from service and replace with a part eligible for installation.

TABLE 3 TO PARAGRAPH (g)(5)—PART REPLACEMENT COMPLIANCE TIMES

Part	Table S/N is listed in	Previously operated in high-thrust model engine	Flight cycle limit from the effective date of this AD
HPT 1st-stage hub P/N 2A5001.	Table 3 of IAE AG NMSB V2500–ENG–72–0720	Yes	1,800 FCs.
HPT 1st-stage hub P/N 2A5001.	Table 3 of IAE AG NMSB V2500–ENG–72–0720	No	2,800 FCs.
HPT 2nd-stage hub P/N 2A4802.	Table 4 of IAE AG NMSB V2500–ENG–72–0720	Yes	3,400 FCs.
HPT 2nd-stage hub P/N 2A4802.	Table 4 of IAE AG NMSB V2500–ENG–72–0720	No	3,800 FCs.

(h) Definitions

(1) For the purposes of this AD, a “part eligible for installation” is an HPT 1st-stage disk or HPT 2nd-stage disk having an S/N that is not listed in IAE AG NMSB V2500–ENG–72–0720 or PW SI No. 189F–23, or an HPT 1st-stage disk or HPT 2nd-stage disk that was not removed from service per the requirements of this AD.

(2) For the purposes of this AD, an “HPT module removal” is when the HPT rotor and stator assembly are removed from the engine.

(3) For the purposes of this AD, “Previously operated in high-thrust model engine” refers to HPT 1st-stage hubs or HPT 2nd-stage hubs that have operated in an IAE AG Model V2527E–A5, V2527M–A5, V2528–D5, V2530–A5, V2531–E5, or V2533–A5 engine for any duration.

(4) For the purposes of this AD, an “engine shop visit” is the induction of an engine into the shop for maintenance involving the separation of pairs of major mating engine flanges, H–P, except for the following situations, which do not constitute an engine shop visit:

(i) Separation of engine flanges solely for the purposes of transportation without subsequent engine maintenance.

(ii) Engine removal for the purpose of performing field maintenance activities at a maintenance facility in lieu of performing them on-wing.

(5) For the purposes of this AD, the date that an AUI inspected part was installed is the date of the authorized release certification for the shop visit at which the part was first installed after the AUI was performed.

(i) Terminating Action to AD 2022–02–09

Compliance with paragraph (g)(1) of this AD satisfies the requirements of AD 2022–02–09.

(j) Alternative Methods of Compliance (AMOCs)

(1) The Manager, AIR–520 Continued Operational Safety Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or local Flight Standards District Office, as appropriate. If sending information directly to the manager of the AIR–520 Continued Operational Safety Branch, send it to the attention of the person identified in paragraph (k) of this AD.

(2) Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the local flight standards district office/certificate holding district office.

(k) Additional Information

For more information about this AD, contact Carol Nguyen, Aviation Safety Engineer, FAA, 2200 South 216th Street, Des Moines, WA 98198; phone: (781) 238–7655; email: carol.nguyen@faa.gov.

(l) Material Incorporated by Reference

(1) The Director of the Federal Register approved the incorporation by reference (IBR) of the service information listed in this paragraph under 5 U.S.C. 552(a) and 1 CFR part 51.

(2) You must use this service information as applicable to do the actions required by this AD, unless the AD specifies otherwise.

(i) International Aero Engines AG (IAE AG) Non-Modification Service Bulletin V2500–ENG–72–0720, dated November 20, 2023.

(ii) Pratt & Whitney (PW) Special Instruction No. 189F–23, dated November 20, 2023.

(3) For IAE AG and PW service information, contact International Aero Engines, AG, 400 Main Street, East Hartford, CT 06118; phone: (860) 565–0140; email: help24@pw.utc.com; website: connect.prattwhitney.com.

(4) You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 1200 District Avenue, Burlington, MA 01803. For information on the availability of this material at the FAA, call (817) 222–5110.

(5) You may view this material at the National Archives and Records Administration (NARA). 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.

Issued on May 31, 2024.

Suzanne Masterson,

Deputy Director, Integrated Certificate Management Division, Aircraft Certification Service.

[FR Doc. 2024–12594 Filed 6–10–24; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT**24 CFR Part 236**

[Docket No. FR–6439–C–02]

RIN 2502–AJ74

Removal of Obsolete Regulations for Section 236 of the National Housing Act; Correction

AGENCY: Office of the Assistant Secretary for Housing—Federal Housing Commissioner, U.S. Department of Housing and Urban Development (HUD).

ACTION: Final rule; correction.

SUMMARY: HUD is correcting a final rule entitled, “Removal of Obsolete Regulations for Section 236 of the National Housing Act” that published on June 4, 2024, to include the rule’s Regulation Identifier Number (RIN).

DATES: Effective July 5, 2024.

FOR FURTHER INFORMATION CONTACT: Aaron Santa Anna, Associate General Counsel for Legislation and Regulations, Department of Housing and Urban Development, 451 7th Street SW, Room 10238, Washington, DC 20410; telephone number 202–708–1793 (this is not a toll-free number). HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech and communication disabilities. To learn more about how to make an accessible telephone call, please visit <https://www.fcc.gov/consumers/guides/telecommunications-relay-service-trs>.

SUPPLEMENTARY INFORMATION: On June 4, 2024 (89 FR 47849), HUD published a final rule titled “Removal of Obsolete Regulations for Section 236 of the National Housing Act.” The rule did not contain a RIN. This document corrects the final rule to include the RIN.

Correction

In the final rule titled “Removal of Obsolete Regulations for Section 236 of the National Housing Act” (89 FR 47849), FR Doc. 2024–12199, beginning on page 47849, in the **Federal Register** issue of June 4, 2024, make the following correction. On page 47849, in the first column, add the RIN in the document heading after the docket number [FR–6439–F–01] to read RIN 2502–A]74.

Aaron Santa Anna,

Associate General Counsel for Legislation and Regulations.

[FR Doc. 2024–12702 Filed 6–10–24; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R05–OAR–2024–0120; FRL–11915–01–R5]

Air Plan Approval; Michigan; Definitions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) is approving a request submitted by the Michigan Department of Environment, Great Lakes, and Energy (EGLE) on February 28, 2024, to revise the Michigan state implementation plan (SIP). The revision is updating the SIP for clarity by removing a redundant definition for “used oil.”

DATES: This direct final rule will be effective August 12, 2024, unless EPA receives adverse comments by July 11, 2024. If adverse comments are received, EPA will publish a timely withdrawal of the direct final rule in the **Federal Register** informing the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R05–OAR–2024–0120 at <https://www.regulations.gov> or via email to langman.michael@epa.gov. For comments submitted at [Regulations.gov](https://www.regulations.gov), follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from the docket. EPA may publish any comment received to its public docket. Do not submit to EPA’s docket at <https://www.regulations.gov> any information you consider to be Confidential Business Information (CBI), Proprietary Business Information (PBI),

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. 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, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section. For the full EPA public comment policy, information about CBI, PBI, or multimedia submissions, and general guidance on making effective comments, please visit <https://www.epa.gov/dockets/commenting-epa-dockets>.

FOR FURTHER INFORMATION CONTACT: Charles Hatten, Air and Radiation Division (AR18J), Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886–6031, hatten.charles@epa.gov. The EPA Region 5 office is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays.

SUPPLEMENTARY INFORMATION: Throughout this document whenever “we,” “us,” or “our” is used, we mean EPA.

I. General Information

On February 28, 2024, EGLE submitted a request to EPA that the definition for the term “used oil” as specified in R 299.9109(p), adopted into the SIP from Michigan’s Hazardous Waste Management Rules, be removed from the SIP. Michigan’s SIP contains an identical definition of “used oil” at R 336.1121(c).

II. What is EPA’s analysis of Michigan’s submission?

In 2015, EPA approved rule R299.9109(p) with a definition for the term “used oil” in Michigan’s SIP. (80 FR 21183, April 17, 2015). However, Michigan EGLE later revised Michigan’s Air Pollution Control Rule in Chapter 336, Part 1, “Definitions”, to include the definition of “used oil” in the general air provisions rule at R336.1121(c) to define the term “used oil” for all the air rules. EPA approved this revision into the Michigan SIP on April 11, 2019 (84 FR 8809). Michigan EGLE eliminated the redundant “used oil” definition by removing R299.9109(p), effective at the state level on October 24, 2019.

Clean Air Act (CAA) Section 110(l) prohibits EPA from approving a SIP

revision if it would interfere with any applicable requirement concerning attainment, reasonable further progress, or any other CAA requirement. The removal of this definition does not interfere with any applicable requirement concerning attainment or any other applicable requirement of the CAA because this definition of “used oil” has also been approved into the SIP in R 336.1121(c). This revision removes a duplicative definition. Further, the removal of a redundant definition of used oil in R 299.9109(p) of Michigan’s Hazardous Waste Management Regulations improves the clarity of Michigan’s Air Pollution Control Rule definition of the term “used oil” for all air rules.

III. What action is EPA taking?

EPA is approving a revision to the Michigan SIP as submitted on February 28, 2024. The revision is updating the SIP for clarity by removing a redundant definition for used oil from Michigan’s SIP.

We are publishing this action without prior proposal because we view this as a noncontroversial amendment and anticipate no adverse comments. However, in the proposed rules section of this **Federal Register** publication, we are publishing a separate document that will serve as the proposal to approve the state plan if relevant adverse written comments are filed. This rule will be effective August 12, 2024 without further notice unless we receive relevant adverse written comments by July 11, 2024. If we receive such comments, we will withdraw this action before the effective date by publishing a subsequent document that will withdraw the final action. All public comments received will then be addressed in a subsequent final rule based on the proposed action. EPA will not institute a second comment period. Any parties interested in commenting on this action should do so at this time. Please note that if EPA receives adverse comment on an amendment, paragraph, or section of this rule and if that provision may be severed from the remainder of the rule, EPA may adopt as final those provisions of the rule that are not the subject of an adverse comment. If we do not receive any comments, this action will be effective August 12, 2024.

IV. Incorporation by Reference

In this rule, EPA is amending regulatory text that includes incorporation by reference. As described in the amendments to 40 CFR part 52 set forth below, EPA is removing provisions of the EPA-Approved Michigan

Regulations from the Michigan SIP, which is incorporated by reference in accordance with the requirements of 1 CFR 51.5.

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993), 13563 (76 FR 3821, January 21, 2011), and 14094 (88 FR 21879, April 11, 2023);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it approves a state program;
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a

tribe has jurisdiction. In those areas of Indian country, the rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

Executive Order 12898 (Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 FR 7629, February 16, 1994) directs Federal agencies to identify and address “disproportionately high and adverse human health or environmental effects” of their actions on minority populations and low-income populations to the greatest extent practicable and permitted by law. EPA defines environmental justice (EJ) as “the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.” EPA further defines the term fair treatment to mean that “no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.”

EGLÉ did not evaluate EJ considerations as part of its SIP submittal; the CAA and applicable implementing regulations neither prohibit nor require such an evaluation. EPA did not perform an EJ analysis and did not consider EJ in this action. Due to the nature of the action being taken here, this action is expected to have a neutral to positive impact on the air quality of the affected area. Consideration of EJ is not required as part of this action, and there is no information in the record inconsistent with the stated goal of E.O. 12898 of achieving EJ for people of color, low-income populations, and Indigenous peoples.

This action is subject to the Congressional Review Act, and EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a “major rule” as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by August 12, 2024. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it

extend the time within which a petition for judicial review may be filed and shall not postpone the effectiveness of such rule or action. Parties with objections to this direct final rule are encouraged to file a comment in response to the parallel notice of proposed rulemaking for this action published in the proposed rules section of this **Federal Register**, rather than file an immediate petition for judicial review of this direct final rule, so that EPA can withdraw this direct final rule and address the comment in the proposed rulemaking. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference.

Dated: June 3, 2024.

Debra Shore,

Regional Administrator, Region 5.

For the reasons stated in the preamble, 40 CFR part 52 is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

- 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

§ 52.1170 [Amended]

- 2. In § 52.1170, the table in paragraph (c) is amended by removing the section heading entitled, “Hazardous Waste Management” and the entry for “R 299.9109(p)”.

[FR Doc. 2024–12519 Filed 6–10–24; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 141

[EPA–HQ–OW–2022–0114; FRL 8543–04–OW]

RIN 2040–AG18

PFAS National Primary Drinking Water Regulation; Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correction.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is correcting formatting and entry designations in a final rule that was published in the **Federal Register** on April 26, 2024. The

rule finalized National Primary Drinking Water Regulations under the Safe Drinking Water Act for five individual per- and polyfluoroalkyl substances (PFAS): perfluorooctanoic acid (PFOA), perfluorooctane sulfonic acid (PFOS), perfluorohexane sulfonic acid (PFHxS), perfluorononanoic acid (PFNA), hexafluoropropylene oxide dimer acid (HFPO-DA, commonly known as GenX Chemicals). The rule finalized a NPDWR for two or more mixtures of PFNA, PFHxS, HFPO-DA and perfluorobutane sulfonic acid (PFBS). This document corrects formatting and entry designations in the final regulation.

DATES: Effective on June 25, 2024.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA-HQ-OW-2022-0114. All documents in the docket are listed on the <https://www.regulations.gov> website. Although listed in the index, 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: Alexis Lan, Office of Ground Water and Drinking Water, Standards and Risk Management Division (Mail Code 4607M), Environmental Protection Agency, 1200 Pennsylvania Avenue NW, Washington, DC 20460; telephone number 202-564-0841; email address: PFASNPDWR@epa.gov.

SUPPLEMENTARY INFORMATION: The EPA is making several corrections for inadvertent errors in the regulatory text for the final rule:

I. Does this action apply to me?

This action makes formatting changes for the incorporation of the April 26, 2024, final PFAS National Primary Drinking Water Regulation into the Code of Federal Regulations. The agency included in the April 26, 2024, final rule a list of those entities that may be potentially affected by the final PFAS National Primary Drinking Water Regulation.

II. What does this correction do?

The EPA issued a final rule in the **Federal Register** on April 26, 2024 (89 CFR 32532) (FRL 8543-02-OW), finalizing National Primary Drinking Water Regulations under the Safe Drinking Water Act for PFAS: PFOA, PFOS, PFHxS, PFNA, HFPO-DA, and as well as two or more mixtures of PFNA, PFHxS, HFPO-DA and PFBS. The EPA inadvertently listed incorrect entry designations in § 141.61. This document corrects the designation of entries in the tables in § 141.61(c)(1) and § 141.61(c)(2). With the corrections to § 141.61(c)(1) and § 141.61(c)(2), the subsequent tables in § 141.61(c) are also renumbered; tables 5 and 6 are changed to tables 3 and 4. These corrections to § 141.61 are also now reflected appropriately in amendatory instructions 7 and 8. This document corrects the final regulation.

III. Why is this correction issued as final rule?

Section 553 of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)(3)(B)) 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 final rule without providing notice and an opportunity for public comment. The EPA has determined that there is a good cause for making this correction final without prior proposal and opportunity for comment, because the EPA inadvertently listed the designation of entries incorrectly in § 141.61 in the document published in the **Federal Register**. The EPA finds that this constitutes good cause under 5 U.S.C. 553(b)(3)(B).

Corrections

In FR Doc. 2024-07773 beginning on page 32532 in the **Federal Register** of April 26, 2024, the EPA is making the following corrections:

§ 141.60 [Corrected]

■ 1. On page 32744, in the third column, in § 141.60, in paragraph (a)(4), “The effective date for paragraphs (c)(34) through (40) of § 141.61 (listed in table 4 to paragraph (c)) is April 26, 2029.” is corrected to read “The effective date for § 141.61(c)(2)(i) through (vii) is April 26, 2029.”

■ 2. On page 32744, starting in the third column, amendatory instruction 8 for § 141.61 and the accompanying regulatory text are corrected to read as follows:

8. Amend § 141.61 by:

- a. In paragraph (a), revising the introductory text and adding a table heading;
- b. In paragraph (b), revising the introductory text and the table heading;
- c. Revising and republishing paragraph (c); and
- d. Adding paragraphs (d) and (e).

The revisions and additions read as follows:

§ 141.61 Maximum contaminant levels for organic contaminants.

(a) The following maximum contaminant levels for volatile organic contaminants apply to community and non-transient, non-community water systems.

Table 1 to Paragraph (a)—Maximum Contaminant Levels for Volatile Organic Contaminants

* * * * *

(b) The Administrator, pursuant to section 1412 of the Act, hereby identifies as indicated in table 2 to this paragraph (b) granular activated carbon (GAC), packed tower aeration (PTA), or oxidation (OX) as the best technology, treatment technique, or other means available for achieving compliance with the maximum contaminant level for organic contaminants identified in paragraphs (a) and (c) of this section, except for per- and polyfluoroalkyl substances (PFAS).

Table 2 to Paragraph (b)—BAT for Organic Contaminants in Paragraphs (a) and (c) of This Section, Except for PFAS

* * * * *

(c) The following maximum contaminant levels (MCLs) in paragraphs (c)(1) and (2) of this section for synthetic organic contaminants apply to community water systems and non-transient, non-community water systems; paragraph (c)(2) of this section also contains health-based water concentrations (HBWCs) for selected per- and poly-fluoroalkyl substances (PFAS) used in calculating the Hazard Index.

(1) *MCLs for Synthetic Organic Contaminants, Except for PFAS.*

CAS No.	Contaminant	MCL (mg/l)
(i) 15972-60-8	Alachlor	0.002
(ii) 116-06-3	Aldicarb	0.003
(iii) 1646-87-3	Aldicarb sulfoxide	0.004
(iv) 1646-87-4	Aldicarb sulfone	0.002
(v) 1912-24-9	Atrazine	0.003
(vi) 1563-66-2	Carbofuran	0.04
(vii) 57-74-9	Chlordane	0.002
(viii) 96-12-8	Dibromochloropropane	0.0002
(ix) 94-75-7	2,4-D	0.07
(x) 106-93-4	Ethylene dibromide	0.00005
(xi) 76-44-8	Heptachlor	0.0004
(xii) 1024-57-3	Heptachlor epoxide	0.0002
(xiii) 58-89-9	Lindane	0.0002
(xiv) 72-43-5	Methoxychlor	0.04
(xv) 1336-36-3	Polychlorinated biphenyls	0.0005
(xvi) 87-86-5	Pentachlorophenol	0.001
(xvii) 8001-35-2	Toxaphene	0.003
(xviii) 93-72-1	2,4,5-TP	0.05
(xix) 50-32-8	Benzo[a]pyrene	0.0002
(xx) 75-99-0	Dalapon	0.2
(xxi) 103-23-1	Di(2-ethylhexyl) adipate	0.4
(xxii) 117-81-7	Di(2-ethylhexyl) phthalate	0.006
(xxiii) 88-85-7	Dinoseb	0.007
(xxiv) 85-00-7	Diquat	0.02
(xxv) 145-73-3	Endothall	0.1
(xxvi) 72-20-8	Endrin	0.002
(xvii) 1071-53-6	Glyphosate	0.7
(xxviii) 118-74-1	Hexachlorobenzene	0.001
(xxix) 77-47-4	Hexachlorocyclopentadiene	0.05
(xxx) 23135-22-0	Oxamyl (Vydate)	0.2
(xxxi) 1918-02-1	Picloram	0.5
(xxxii) 122-34-9	Simazine	0.004
(xxxiii) 1746-01-6	2,3,7,8-TCDD (Dioxin)	3×10^{-8}

(2) MCLs and HBWCs for PFAS.

CAS. No.	Contaminant	MCL (mg/l) (unless otherwise noted)	HBWC (mg/l) for Hazard Index calculation
(i) Not applicable	Hazard Index PFAS (HFPO-DA, PFBS, PFHxS, and PFNA).	1 (unitless) ¹	Not applicable.
(ii) 122499-17-6	HFPO-DA	0.00001	0.00001.
(iii) 45187-15-3	PFBS	No individual MCL	0.002.
(iv) 108427-53-8	PFHxS	0.00001	0.00001.
(v) 72007-68-2	PFNA	0.00001	0.00001.
(vi) 45285-51-6	PFOA	0.0000040	Not applicable.
(vii) 45298-90-6	PFOS	0.0000040	Not applicable.

¹ The PFAS Mixture Hazard Index (HI) is the sum of component hazard quotients (HQs), which are calculated by dividing the measured component PFAS concentration in water by the relevant health-based water concentration when expressed in the same units (shown in ng/l for simplification). The HBWC for PFHxS is 10 ng/l; the HBWC for HFPO-DA is 10 ng/l; the HBWC for PFNA is 10 ng/l; and the HBWC for PFBS is 2000 ng/l.

Hazard Index = $\frac{[HFPO-DA_{\text{water}} \text{ ng/l}]/[10 \text{ ng/l}] + ([PFBS_{\text{water}} \text{ ng/l}]/[2000 \text{ ng/l}] + ([PFNA_{\text{water}} \text{ ng/l}]/[10 \text{ ng/l}]) + ([PFHxS_{\text{water}} \text{ ng/l}]/[10 \text{ ng/l}])}{\text{concentration}}$

HBWC = health-based water concentration

HQ = hazard quotient

ng/l = nanograms per liter

PFAS_{water} = the concentration of a specific PFAS in water

(d) The Administrator, pursuant to section 1412 of the Act, hereby identifies in table 3 to this paragraph (d)

the best technology, treatment technique, or other means available for achieving compliance with the maximum contaminant levels for all regulated PFAS identified in paragraph (c) of this section:

TABLE 3 TO PARAGRAPH (d)—BEST AVAILABLE TECHNOLOGIES FOR PFAS LISTED IN PARAGRAPH (c) OF THIS SECTION

Contaminant	BAT
Hazard Index PFAS (HFPO-DA, PFBS, PFHxS, and PFNA)	Anion exchange, GAC, reverse osmosis, nanofiltration.
HFPO-DA	Anion exchange, GAC, reverse osmosis, nanofiltration.
PFHxS	Anion exchange, GAC, reverse osmosis, nanofiltration.
PFNA	Anion exchange, GAC, reverse osmosis, nanofiltration.

TABLE 3 TO PARAGRAPH (d)—BEST AVAILABLE TECHNOLOGIES FOR PFAS LISTED IN PARAGRAPH (c) OF THIS SECTION—Continued

Contaminant	BAT
PFOA	Anion exchange, GAC, reverse osmosis, nanofiltration.
PFOS	Anion exchange, GAC, reverse osmosis, nanofiltration.

(e) The Administrator, pursuant to section 1412 of the Act, hereby identifies in table 4 to this paragraph (e) the affordable technology, treatment technique, or other means available to systems serving 10,000 persons or fewer for achieving compliance with the maximum contaminant levels for all regulated PFAS identified in paragraph (c) of this section:

TABLE 4 TO PARAGRAPH (e)—SMALL SYSTEM COMPLIANCE TECHNOLOGIES (SSCTs) FOR PFAS

Small system compliance technology ¹	Affordable for listed small system categories ²
Granular Activated Carbon.	All size categories.
Anion Exchange	All size categories.
Reverse Osmosis, Nanofiltration ³ .	3,301–10,000.

¹ Section 1412(b)(4)(E)(ii) of SDWA specifies that SSCTs must be affordable and technically feasible for small systems.
² The Act (ibid.) specifies three categories of small systems: (i) those serving 25 or more, but fewer than 501, (ii) those serving more than 500, but fewer than 3,301, and (iii) those serving more than 3,300, but fewer than 10,001.
³ “Technologies reject a large volume of water and may not be appropriate for areas where water quantity may be an issue.

Bruno Pigott,
Assistant Administrator.
[FR Doc. 2024–12645 Filed 6–10–24; 8:45 am]
BILLING CODE 6560–50–P

DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
50 CFR Part 622
[Docket No. 200124–0029; RTID 0648–XD967]
Fisheries of the Caribbean, Gulf of Mexico, and South Atlantic; Reef Fish Fishery of the Gulf of Mexico; 2024 Red Snapper Private Angling Component Accountability Measure in Federal Waters Off Alabama, Florida, and Mississippi
AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and

Atmospheric Administration (NOAA), Commerce.
ACTION: Temporary rule, accountability measure.
SUMMARY: Through this temporary rule, NMFS implements accountability measures for the red snapper recreational sector private angling component in the Gulf of Mexico (Gulf off Alabama, Florida, and Mississippi for the 2024 fishing year. Based on information provided by the Alabama Department of Conservation and Natural Resources (ADCNR), the Florida Fish and Wildlife Conservation Commission (FWC), and the Mississippi Department of Marine Resources (MDMR), NMFS has determined that landings in each of these States exceeded the State’s 2023 regional management area private angling component annual catch limits (ACL) for Gulf red snapper. Therefore, NMFS reduces the Alabama, Florida, and Mississippi 2024 private angling component ACLs. This reduction will remain in effect through the remainder of the current fishing year on December 31, 2024.
DATES: This temporary rule is effective from 12:01 a.m., local time, on June 13, 2024, until 12:01 a.m., local time, on January 1, 2025.
FOR FURTHER INFORMATION CONTACT: Frank Helies, NMFS Southeast Regional Office, 727–824–5305, frank.helies@noaa.gov.
SUPPLEMENTARY INFORMATION: NMFS manages the Gulf reef fish fishery, which includes red snapper, under the Fishery Management Plan for the Reef Fish Resources of the Gulf of Mexico (FMP). The Gulf of Mexico Fishery Management Council prepared the FMP, which was approved by the Secretary of Commerce, and NMFS implements the FMP through regulations at 50 CFR part 622 under the authority of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). All red snapper weights discussed in this temporary rule are in round weight.
In 2015, Amendment 40 to the FMP established two components within the recreational sector fishing for red snapper: the private angling component, and the Federal charter vessel and headboat (for-hire) component (80 FR

22422, April 22, 2015). In 2020, NMFS implemented Amendments 50 A–F to the FMP, which delegated authority to the Gulf States (Alabama, Florida, Louisiana, Mississippi, and Texas) to establish specific management measures for the harvest of red snapper in Federal waters of the Gulf by the private angling component of the recreational sector (85 FR 6819, February 6, 2020). These amendments allocated a portion of the private angling ACL to each State, and each State is required to constrain landings to its allocation as part of State management.
As described at 50 CFR 622.39(a)(2)(i), the Gulf red snapper recreational sector quota (ACL) is 7,991,900 pounds (lb) (3,625,065 kilograms(kg)) and the recreational private angling component quota (ACL) is 4,611,326 lb (2,091,662 kg). These catch limits are based, in part, on landings estimates generated by the Marine Recreational Information Program (MRIP) and, prior to the 2023 fishing year, the State-specific ACLs for Alabama, Florida, Louisiana, Mississippi were also MRIP-based. These MRIP-based State ACLs are not directly comparable to the landings estimates produced by each State’s survey. Therefore, in 2023, NMFS implemented a framework action under the FMP to calibrate the red snapper ACLs for Alabama, Florida, Louisiana, and Mississippi so they could be directly compared to the landings estimates produced by each of those State’s data collection program (Calibration Framework)(87 FR 74014, December 2, 2022). This framework action established State-specific calibration ratios that NMFS applied to the MRIP-based ACLs to establish State-survey based ACLs, which allow a direct comparison to the landings estimates produced by each State.
On May 14, 2024, NMFS published a final rule for a framework action to the FMP that modified the State-specific ratios for Alabama, Florida, and Mississippi and modified each of these State’s private angling component ACL based on the new ratios (89 FR 41896). That final rule will be effective on June 13, 2024, and adjusts the State-survey based ACLs as follows: the Alabama regional management area private angling component ACL will be 664,552

lb (301,436 kg) (50 CFR 622.23(a)(1)(ii)(A)); the Florida regional management area private angling component ACL will be 2,769,631 lb (1,256,283 kg) (50 CFR 622.23(a)(1)(ii)(B)), and the Mississippi regional management area private angling component ACL will be 82,342 lb (37,350 kg) (50 CFR 622.23(a)(1)(ii)(D)). The MRIP-based State ACLs, described in the regulations as the Federal equivalent, will remain the same.

Regulations at 50 CFR 622.23(b) require that if a State's red snapper private angling component landings exceed the applicable State's component ACL, then in the following fishing year, that State's private angling ACL will be reduced by the amount of that ACL overage in the prior fishing year. Based on data provided by the ADCNR, NMFS has determined that 2023 landings of red snapper in Alabama for the private angling component, which includes landings for State charter vessels, were 596,083 lb (270,379 kg); which is 4,898 lb (2,222 kg) greater than the 2023 Alabama State-survey based ACL. Based on data provided by the FWC, NMFS has determined that 2023 landings of red snapper in Florida for the private angling component, which includes landings for State charter vessels, were 2,204,136 lb (999,779 kg); which is 12,821 lb (5,816 kg) greater than the 2023 Florida State-survey based ACL. Based on data provided by the MDMR, NMFS has determined that 2023 landings of red snapper in Mississippi for the private angling component, which includes landings for State charter vessels, were 80,675 lb (36,594 kg); which is 17,813 lb (8,080 kg) greater than the 2023 Mississippi State-survey based ACL. Accordingly, for the 2024 fishing year, this temporary rule reduces the Alabama, Florida, and Mississippi 2024 State-survey based ACLs by the amount of the overages. These reductions results in a revised 2024 private angling ACL for Alabama of 659,654 lb (299,214 kg), a revised 2024 private angling ACL for Florida of 2,756,810 lb (1,250,468 kg), and a revised 2024 private angling ACL for Mississippi of 64,529 lb (29,270 kg).

The recreational private angling component ACLs for the other Gulf State management areas (Louisiana and Texas) for 2024 are unaffected by this temporary rule. The reductions in the 2024 red snapper private angling component ACLs for the Alabama, Florida, and Mississippi regional management areas are effective at 12:01 a.m., local time, on June 13, 2024, and will remain in effect until 12:01 a.m., local time, on January 1, 2025.

The ADCNR, FWC, and MDMR are responsible for ensuring that 2024 private angling component landings in each applicable State's regional management area do not exceed the adjusted 2024 Alabama, Florida, and Mississippi ACLs. NMFS notes that after the ADCNR, FWC, and MDMR identified that ACL overages had occurred in 2023, they adjusted their respective 2024 red snapper private angling fishing seasons to account for the reduction in the ACLs as required by the regulations at 50 CFR 622.23(b) and implemented through this temporary rule.

Classification

NMFS issues this action pursuant to section 305(d) of the Magnuson-Stevens Act. This action is required under 50 CFR 622.23(b) which was issued pursuant to section 304(b) of the Magnuson-Stevens Act, 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 opportunity for public comment on this action. Such procedures are unnecessary because the rule implementing the post-season ACL adjustment authority has already been subject to notice and comment, and all that remains is to notify the public of the ACL overage adjustment to reduce the private angling component ACLs for the Alabama, Florida, and Mississippi regional management areas. Such procedures are contrary to the public interest because a failure to implement the ACL overage adjustments immediately may result in confusion among the public about what ACL is in effect for Alabama, Florida, and Mississippi for the 2024 fishing year. This action is based on the best scientific information available.

For the aforementioned reasons, there is also good cause to waive the 30-day delay in the effectiveness of the action under 5 U.S.C. 553(d)(3).

Authority: 16 U.S.C. 1801 *et seq.*

Dated: June 5, 2024.

Karen H. Abrams,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2024-12693 Filed 6-10-24; 8:45 am]

BILLING CODE 3510-22-P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 231215-0305; RTID 0648-XE028]

Fisheries of the Northeastern United States; Summer Flounder Fishery; Quota Transfer From North Carolina to Virginia

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Temporary rule; quota transfer.

SUMMARY: NMFS announces that the State of North Carolina is transferring a portion of its 2024 commercial summer flounder quota to the Commonwealth of Virginia. This adjustment to the 2024 fishing year quota is necessary to comply with the Summer Flounder, Scup, and Black Sea Bass Fishery Management Plan (FMP) quota transfer provisions. This announcement informs the public of the revised 2024 commercial quotas for North Carolina and Virginia.

DATES: Effective June 10, 2024 through December 31, 2024.

FOR FURTHER INFORMATION CONTACT: Laura Deighan, Fishery Management Specialist, (978) 281-9184.

SUPPLEMENTARY INFORMATION:

Regulations governing the summer flounder fishery are found in 50 CFR 648.100 through 648.111. These regulations require annual specification of a commercial quota that is apportioned among the coastal states from Maine through North Carolina. The process to set the annual commercial quota and the percent allocated to each state is described in § 648.102, and the final 2024 allocations were published on December 21, 2023 (88 FR 88266).

The final rule implementing amendment 5 to the Summer Flounder FMP, as published in the **Federal Register** on December 17, 1993 (58 FR 65936), provided a mechanism for transferring summer flounder commercial quota from one state to another. Two or more states, under mutual agreement and with the concurrence of the NMFS Greater Atlantic Regional Administrator, can transfer or combine summer flounder commercial quota under § 648.102(c)(2). The Regional Administrator is required to consider three criteria in the evaluation of requests for quota transfers or combinations: (1) the transfers or

combinations would not preclude the overall annual quota from being fully harvested; (2) the transfers address an unforeseen variation or contingency in the fishery; and (3) the transfers are consistent with the objectives of the FMP and the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). The Regional Administrator has determined these three criteria have been met for the transfer approved in this notification.

North Carolina is transferring 15,576 pounds (lb; 7,065 kilograms (kg)) to

Virginia through a mutual agreement between the states. This transfer was requested to repay landings made by an out-of-state permitted vessel under a safe harbor agreement. The revised summer flounder quotas for 2024 are: North Carolina, 2,355,548 lb (1,068,459 kg); and Virginia, 1,899,556 lb (861,624 kg).

Classification

NMFS issues this action pursuant to section 305(d) of the Magnuson-Stevens Act. This action is required by 50 CFR

648.102(c)(2)(i) through (iv), which was issued pursuant to section 304(b), and is exempted from review under Executive Order 12866.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: June 5, 2024.

Karen H. Abrams,

Acting Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2024–12668 Filed 6–10–24; 8:45 am]

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Proposed Rules

Federal Register

Vol. 89, No. 113

Tuesday, June 11, 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 AGRICULTURE

Animal and Plant Health Inspection Service

9 CFR Parts 56, 145, 146, and 147

[Docket No. APHIS–2022–0056]

RIN 0579–AE74

National Poultry Improvement Plan and Auxiliary Provisions

AGENCY: Animal and Plant Health Inspection Service, USDA.

ACTION: Proposed rule.

SUMMARY: We are proposing to amend the regulations governing the National Poultry Improvement Plan (NPIP). These amendments would, among other things, condition indemnity for low pathogenicity avian influenza on adherence to biosecurity plans, clarify existing provisions of the regulations, fix editorial errors, and align the regulations more closely with current producer practices. These proposed changes were voted on and approved by the voting delegates at the NPIP's 2022 National Plan Conference.

DATES: We will consider all comments that we receive on or before August 12, 2024.

ADDRESSES: You may submit comments by either of the following methods:

- *Federal eRulemaking Portal:* Go to www.regulations.gov. Enter APHIS–2022–0056 in the Search field. Select the Documents tab, then select the Comment button in the list of documents.

- *Postal Mail/Commercial Delivery:* Send your comment to Docket No. APHIS–2022–0056, Regulatory Analysis and Development, PPD, APHIS, Station 3A–03.8, 4700 River Road, Unit 118, Riverdale, MD 20737–1238.

Supporting documents and any comments we receive on this docket may be viewed at www.regulations.gov or in our reading room, which is located in room 1620 of the USDA South Building, 14th Street and Independence Avenue SW, Washington, DC. Normal

reading room hours are 8 a.m. to 4:30 p.m., Monday through Friday, except holidays. To be sure someone is there to help you, please call (202) 7997039 before coming.

FOR FURTHER INFORMATION CONTACT: Dr. Elena Behnke, DVM, Senior Coordinator, National Poultry Improvement Plan, VS, APHIS, USDA, 1506 Klondike Road, Suite 301, Conyers, GA 30094–5104; (770) 922–3496.

SUPPLEMENTARY INFORMATION:

Background

The National Poultry Improvement Plan (NPIP, also referred to below as “the Plan”) is a cooperative Federal-State-industry mechanism for controlling certain poultry diseases. The Plan consists of a variety of programs intended to prevent and control poultry diseases. Participation in all Plan programs is voluntary, but breeding flocks, hatcheries, and dealers must first qualify as “U.S. Pullorum-Typhoid Clean” as a condition for participating in the other Plan programs.

The Plan identifies States, independent flocks, hatcheries, dealers, and slaughter plants that meet certain disease control standards specified in the Plan's various programs. As a result, customers can buy poultry that has tested clean of certain diseases or that has been produced under disease-prevention conditions.

The regulations in 9 CFR parts 56, 145, 146, and 147 (referred to below as the regulations) contain the provisions of the Plan. The Animal and Plant Health Inspection Service (APHIS) amends these provisions from time to time to incorporate new scientific information and technologies within the Plan, and to ensure the plan reflects changes to the poultry industry itself. The changes we are proposing, which are discussed below, were approved by the voting delegates at the Plan's 2022 Biennial Conference. Participants and voting delegates at the Biennial Conference represented the poultry industry, flock owners, breeders, hatchery men, slaughter plants, poultry veterinarians, diagnostic laboratory personnel, Official State Agencies from cooperating States, and other poultry industry affiliates.

In this document, we first discuss editorial oversights from the last rulemaking to update the NPIP

regulations that we are proposing to correct in this proposed rule. Then, we address the other proposals, in the order in which they would appear in the regulations. Finally, we discuss proposed changes to the Program Standards document that accompanies the regulations and provides guidance on their application.

Editorial Oversights From the Previous Rulemaking

On October 5, 2020, we published a final rule in the *Federal Register* (85 FR 62559–62572, Docket No. APHIS–2018–0062)¹ that codified changes to the regulations that were voted on and approved by the voting delegates at the NPIP's 2018 National Plan Conference.

Among the changes to the regulations in that October 2020 final rule were revisions to the regulations in part 56, which govern the payment of indemnity for low pathogenicity avian influenza (LPAI). As one of these revisions, we intended to revise references to cleaning and disinfection for LPAI to “virus elimination” throughout part 56, or otherwise add the term “virus elimination” after references to cleaning and disinfection. As we stated in the proposed rule on which the October 2020 final rule was based, “virus elimination” is the term used in many foreign countries for cleaning and disinfection measures conducted to destroy or eliminate all LPAI virus on an affected premises, and we wished to underscore the restrictive sense in which cleaning and disinfection was being used in the regulations in part 56.

However, while we updated the terminology in several sections in part 56, we inadvertently overlooked instances in §§ 56.3 and 56.5 in which the terminology was not updated. We propose to add references to virus elimination in these two sections.

In the October 2020 final rule, we added provisions throughout the regulations for a U.S. Newcastle Disease Clean classification. Our intent was to indicate that, for that classification, a minimum of 30 birds per flock must test negative using an approved test at intervals of 90 days, or, alternatively, a sample of fewer than 30 birds may be tested, and found negative, at any one time if all pens are equally represented

¹ To view the final rule, go to www.regulations.gov and enter APHIS–2018–0062 in the Search field.

and a total of 30 birds is tested within each 90-day period, and, regardless of which of the two foregoing testing options is chosen, during each 90-day period, all primary spent fowl, up to a maximum of 30, must test negative within 21 days prior to movement. However, due to the punctuation used for these provisions, they could be construed to mean that primary spent fowl testing is optional depending on the flock testing protocol used. This was not our intent, and we are revising the Newcastle Disease Clean classification provisions throughout the NPIP regulations to align them with our intent.

In the October 2020 final rule, we added a subpart J to part 145 of the regulations, which added testing regimes, terminology, and programs specifically designed for the game bird industry. However, in several instances where sections or subparts are listed within the regulations, we inadvertently neglected to update the lists to include references to this new subpart J. We are correcting this oversight throughout part 145.

In adding subpart J to part 145, we stated, in paragraph (e) of § 145.102, that it was recommended that gallinaceous flocks that participate in the plan and waterfowl be kept separate. However, our definition of the term *game bird* in § 145.101 indicated that it was limited to domesticated fowl; this would preclude a producer who has waterfowl on the same premises from participating under the regulations in subpart J. We are revising paragraph (e) to clarify that gallinaceous flocks and waterfowl may not be raised on the same premises, and, if they are, they must be registered under subpart E of part 145 instead. This subpart contains provisions of the plan specifically designed for producers of hobbyist poultry, exhibition poultry, and raised-for-release waterfowl.

In § 145.103 of subpart J, we included a typographical error in which the word “Typhoid” was misspelled “Typhid.” We are correcting this misspelling.

Subpart E of part 146 of the regulations contains definitions and requirements for Plan participants within the game bird, commercial waterfowl, and raised-for-release waterfowl industries who produce meat- or egg-type flocks. In the proposed rule on which the October 2020 final rule was based, we proposed to update the terminology in subpart E to match other subparts within part 146 by replacing the term “commercial” with “egg/meat-type.” However, we neglected to make corresponding changes to §§ 146.3, 146.6, and 146.9, which contain references to the types of commercial

flocks that may participate in the plan under the provisions in part 146. We also neglected to make a similar harmonizing change in paragraph (a)(9) of § 147.46. We are correcting these oversights by harmonizing the language accordingly.

Proposed Revisions to Part 56

As we mentioned above, the regulations in part 56 govern the payment of indemnity for LPAI. Section 56.1 contains definitions of terms used within that part. We are proposing several revisions to this section. First, we are proposing to add a definition of the *National Poultry Improvement Plan (NPIP) Program Standards*. As we do in § 145.1 of the NPIP regulations, we propose to define the term as “A document that contains tests and sanitation procedures approved by the Administrator pursuant to § 147.53 of this chapter.” Also consistent with that definition in § 145.1, the proposed definition would further specify how the Program Standards may be obtained. The regulations in part 56 currently do not refer to the NPIP Program Standards, however, as discussed below, we are proposing to add references to them and consider a definition warranted in light of those proposed additions.

Currently, § 56.1 defines *Virus elimination* (VE) as “Cleaning and disinfection measures conducted to destroy or eliminate all AI virus on an affected premises.” However, virus elimination may also include methods such as fallowing for premises with dirt floors. To reflect this, we are proposing that virus elimination be defined as “Cleaning and disinfection or other measures conducted to destroy or eliminate all AI virus on the premises.”

Currently, paragraph (b) of § 56.3 provides that the Administrator of APHIS is authorized to pay 100 percent of costs and/or compensation for activities listed in paragraphs (a)(1) through (3) of the section, except for poultry that are described by the categories in the subparagraphs of paragraph (b). The section further specifies that the Administrator may only pay 25 percent of costs for infected or exposed poultry described in any of those categories.

However, the categories in these subparagraphs, in certain instances, currently contain double negatives, which could make it difficult for producers to ascertain whether they qualified for 100 percent or 25 percent of the listed activities for which cost or compensation may be paid. To assist in readability, we are restructuring the introductory text of paragraph (b) so that it provides that producers meeting the

conditions in paragraphs (b)(1) or (2) would be eligible for 100 percent of costs and/or compensation, and we are restructuring these subparagraphs so that they contain positive conditions that must be met in order to be eligible for 100 percent indemnification. Finally, we are adding paragraph (b)(3) which would articulate the categories that are eligible for 25 percent, rather than 100 percent. Again, it is not our intent in these revisions to change the eligibility requirements, but simply to make them easier to interpret. To that end, in the regulatory text at the end of this document, we lay out our proposed revision to paragraph (b) in its entirety for ease of readability and public comment. We also request specific public comment regarding whether there is a different structure for the section that would be clearer and more readable than our proposed revisions.

Section 56.5 contains provisions regarding destruction and disposal of poultry, as well as cleaning and disinfection (virus elimination) of premises, conveyances, and materials. Within that section, paragraph (c) contains provisions regarding the conditions under which infected or exposed poultry for H5/H7 LPAI may be controlled marketed, rather than depopulated, at the discretion of the cooperating State agency and APHIS. The requirements provide that:

- Poultry infected with or exposed to H5/H7 LPAI must not be transported to a market for controlled marketing until approved by the Cooperating State Agency in accordance with the initial State response and containment plan, which is described in § 56.10 of the regulations.

- Within 7 days prior to slaughter, each flock to be moved for controlled marketing must be tested for H5/H7 LPAI using a test approved by the Cooperating State Agency and found to be free of the virus.

- Routes to slaughter must avoid other commercial poultry operations whenever possible. All load-out equipment, trailers, and trucks used on the premises that have housed poultry must undergo virus elimination procedures and not enter other poultry premises or facilities for 48 hours after the virus elimination procedures have been completed.

- Flocks moved for controlled marketing must be the last poultry marketed during the week they are marketed.

We are proposing to add an additional requirement, that the poultry must be monitored daily for the development of additional and/or increased severity of clinical signs with scheduled flock

observation, tracking, and recording flock(s) mortality, taking action as directed by the Official State Agency. We consider this provision necessary because controlled marketing permits the movement of birds known to be infected with or exposed to disease, and because poultry that initially present symptoms consistent with LPAI may subsequently present symptoms associated with a disease with more acute morbidity, such as HPAI. Daily monitoring and coordination with the Official State Agency is therefore appropriate to address this possible risk. To that end, in the regulatory text at the end of this document, we lay out this new provision in its entirety as proposed paragraph (c)(1)(ii) of § 56.5.

Section 56.10 sets forth requirements for initial State response and containment plans for LPAI. Among the current requirements for initial State response and containment plans is that a minimum biosecurity plan must be followed by all poultry producers in the State as indicated in paragraph (a)(2). We are proposing to revise this requirement in several manners. First, as articulated in § 56.3, a biosecurity plan is not required of all producers as a condition for LPAI indemnity, but rather those meeting certain size thresholds. As a result, we would clarify that the initial State response and containment plan must require biosecurity plans for poultry producers based on their flock size as articulated in § 56.3, and, if applicable, contracting parties with such producers.

Second, our experience with avian influenza outbreaks, most notably the highly pathogenic avian influenza (HPAI) outbreak of 2022 and 2023, has suggested that the requirement needs a mechanism to ensure that the biosecurity plans are in fact being followed. As a result, we would amend the requirement for biosecurity plans to specify that the Official State Agency must determine that they are in place and being followed within the State. Likewise, we would specify that the Official State Agency must audit the plans for compliance with the biosecurity principles approved by the Administrator. These revisions would, in turn, authorize Official State Agencies to take on a role of greater oversight within their State regarding the implementation and maintenance of biosecurity plans. Finally, we would provide that the Program Standards document, particularly Standard E, contains the biosecurity principles approved by the Administrator. To that end, in the regulatory text at the end of this document, we lay out our proposed

revision to § 56.10 in its entirety for ease of readability and public comment.

Proposed Revisions to Part 145

Section 145.1 of the regulations provides general definitions of terms used within the NPIP regulations. We are proposing several revisions to this section.

Currently, the definition for *Fowl typhoid or typhoid* is “a disease of poultry caused by *Salmonella gallinarum*,” and the definition for *Pullorum disease or pullorum* is “A disease of poultry caused by *Salmonella pullorum*.” However, since these definitions were added to the regulations, the accepted nomenclature for *Salmonella* spp. has changed, and *Salmonella* is now classified with greater specificity: Not only by species, but also by subspecies, serovar, and biovar. Moreover, it is that specific pathogenic biovar that the NPIP regulations refer to, rather than *Salmonella* species in the broad sense. We are proposing to update the definitions for *Fowl typhoid or typhoid* and *Pullorum disease or pullorum* accordingly.

The definition for *Hatchery* currently is “Hatchery equipment on one premises operated or controlled by any person for the production of baby poultry.” However, hatcheries, such as incubation facilities, may be devoted solely to the production of embryonated eggs. We are updating the definition accordingly.

Likewise, the definition for *Multiplier breeding stock* is “A flock that is intended for the production of hatching eggs used for the purpose of producing progeny for commercial egg or meat production or for other nonbreeding purposes.” However, breeding stock may include fertile eggs, even if the eggs are not yet hatching. We would remove the word “hatching” and add the word “fertile” in its place.

The definition for *Reactor* currently provides that a reactor is a bird that has a positive reaction to a test, required or recommended in this part or in accordance with the NPIP regulations in 9 CFR part 147, for any poultry disease for which a program has been established within the NPIP. Currently, § 145.14 of the regulations specifies that reactors are considered suspects under the regulations until additional confirmatory testing has been conducted in accordance with the regulations; however, the definition of *Reactor* does not refer to this provision. As a result, we are proposing to amend the definition of *Reactor* to include the provision that confirmatory testing must

be conducted before a suspect is reclassified as a reactor.

Finally, we are proposing to add a definition of *Salmonella Enteritidis*. Provisions for a Clean program for *Salmonella Enteritidis* exist within the regulations, but the term is not currently defined. We are proposing to define it as “A bacteria found in poultry caused by *Salmonella enterica* subspecies *enterica* serovar *Enteritidis* (*Salmonella Enteritidis*).”

Section 145.10 of the regulations contains illustrative designs of emblems that flocks and products may be designated with based on their participation in various provisions of the Plan. While the regulations currently provide for a U.S. Newcastle Clean program, U.S. Avian influenza clean compartments, and U.S. Newcastle clean compartments, there are not currently corresponding illustrative designs for this program and these compartments in § 145.10. We propose to add illustrative designs for them.

Section 145.14 contains poultry testing requirements within the NPIP. We are proposing a number of revisions to the section.

The introductory text to the section currently indicates that, for plan programs in which a representative sample may be tested in lieu of an entire flock, the minimum number tested shall be 30 birds per house, unless otherwise specified within the Plan program, with at least 1 bird taken from each pen and unit in the house testing. The sentence further specifies that this does not apply for the ostrich emu, rhea, and cassowary program set forth in § 145.63(a) of the regulations.

The intent of the sentence is to direct producers, including those ostrich, emu, rhea, and cassowary producers enrolled in the program set forth in § 145.63, to the relevant testing requirements for their program(s), and then provides general requirements for test samples within the context of those specific program testing requirements. However, the sentence could be read to indicate that it is of general applicability except in certain outlying situations when program testing requirements indicate otherwise. Moreover, the sentence could be construed to mean either that it sets forth minimum testing requirements for ostrich, emu, rhea, and cassowary producers enrolled in the program set forth in § 145.63(a), while all other producers should follow program testing requirements, or that it does not apply to ostrich, emu, rhea, and cassowary producers at all, who should instead follow the requirements of

§ 145.63. We are proposing to revise the sentence to clarify its intent.

Paragraph (a)(1) provides the official blood tests that may be used for Pullorum-Typhoid within the program, and specifies that the tests must be conducted in accordance with part 147 of the regulations. Guidance and policy related to testing is also found within Program Standards document, in Program Standard A, however. We would indicate that Program Standard A is also operative when conducting testing.

Paragraph (a)(6) specifies the manner in which poultry from flocks undergoing qualification testing for participation in the NPIP that have a positive reaction to an official blood test must be subsequently evaluated. Among other provisions, it specifies that, when reactors are submitted to an authorized laboratory within 10 days of the date of reading of the official blood test, and the bacteriological examination fails to demonstrate pullorum-typhoid infection, the Official State Agency shall presume that the flock has no pullorum-typhoid reactors. However, if poultry from the flock has had a non-negative reaction to an official blood test for pullorum-typhoid, by definition it is a reactor for pullorum-typhoid, and the culture from the bacteriological examination is intended to ascertain whether the poultry is affected with *Salmonella* Pullorum or *Salmonella* Gallinarum, not whether it has reacted to a pullorum-typhoid test. It already has so reacted by the time of the culture.

As a result, we would clarify that if the bacteriological examination and culture fails to demonstrate pullorum-typhoid infection, the Official State Agency may determine that the flock is not infected with *Salmonella* Pullorum or *Salmonella* Gallinarum, but the poultry are still pullorum-typhoid reactors.

Section 145.33 sets forth terminology and classification provisions for multiplier meat-type chicken breeding flocks and their products, while § 145.43 sets forth terminology and classification provisions for turkey breeding flocks and their products. Both sections currently contain provisions for a U.S. Sanitation monitored program for the prevention and control of Salmonellosis. In both sections, the relevant programs allow owners of flocks found infected with paratyphoid *Salmonella* to vaccinate the flocks with an autogenous bacterin with a potentiating agent. However, the testing for *Salmonella* specified in the programs is environmental testing, rather than flock testing; if the environmental testing in the section has a non-negative

test for *Salmonella* spp. it does not necessarily mean the flock itself is infected, and the flock may, accordingly, be vaccinated for *Salmonella* typhoid irrespective of the environmental testing. We are proposing to delete the current vaccination allowance because it is not germane to the programs; producers may choose to vaccinate their flocks for *Salmonella* typhoid or not with no bearing on the programs' provisions.

Paragraph (l) of § 145.33 sets forth a U.S. Avian Influenza clean program for multiplier meat-type chicken breeding flocks and their products. Paragraph (l)(1) currently requires either a sample of at least 15 birds to be tested negative at intervals of 90 days; or a sample of fewer than 15 birds to be tested, and found to be negative, at any one time if all pens are equally represented and a total of 15 birds is tested within each 90-day period; or the flock to be tested at intervals of 30 days or less and found to be negative, and a total of 15 samples are collected and tested within each 90-day period. Paragraph (l)(2) of the section currently specifies that, during each 90-day period, all multiplier spent fowl, up to a maximum of 30, must be tested and found negative for avian influenza within 21 days prior to movement to slaughter. As written, paragraph (l)(2) could be construed to allow one multiplier spent fowl to be tested within 21 days prior to movement, and to allow this testing to count towards the requisite testing in paragraph (l)(1). This would constitute insufficient testing for avian influenza to provide assurances that a flock is "clean," however. Accordingly, we are proposing to remove paragraph (l)(2) and require instead that 15 birds are tested and found negative for avian influenza within 21 days prior to movement to slaughter regardless of the date of the previous test. This would align the minimum testing sample for multiplier spent fowl with the minimum test sample requirements for the flock as a whole.

Paragraph (m) of § 145.33 sets forth a U.S. *Salmonella* Enteritidis Monitored program for multiplier meat-type breeders wishing to monitor their flocks. Paragraph (m)(2) provides actions that must be taken with respect to test results generated from the monitoring program. When the program was first added to § 145.33, the section pertained to both primary meat-type breeders and multiplier meat-type breeders, and the provisions in paragraph (m)(2) specifically addressed primary breeders. However, primary breeders now have their own subpart, subpart H, within the regulations. For multiplier meat-type

breeders, because the offspring of the breeders rather than the breeders themselves enter commercial production, it is sufficient for the participating breeder to have a monitoring and testing program in place for *Salmonella enteritidis*, with the appropriate actions following test results determined by the breeders themselves. In other words, it is the existence of the monitoring program, rather than the results of testing conducted under the auspices of the monitoring program, that results in the classification for multiplier meat-type breeders. We propose to amend paragraph (m)(2) accordingly.

As we mentioned above, § 145.43 sets forth terminology and classification provisions for turkey breeding flocks and their products. Paragraph (c) of the section contains provisions for U.S. *M. Gallisepticum* Clean status for such flocks and products, while paragraph (d) contains provisions for U.S. *M. Meleagridis* Clean status, and paragraph (e) contains provisions for

M. Synoviae Clean status. All three paragraphs contain separate testing protocols for male flocks and female flocks, but no protocols for mixed flocks of male and female turkeys. We propose to add such protocols.

Paragraph (c)(1) of § 145.43 also indicates that testing must find no *M. Gallisepticum* reactors as one of the conditions for clean status. However, as noted previously, a reactor is, by definition, not necessarily a positive sample, but rather a suspect that has been sent for additional confirmatory testing by an authorized laboratory or Federal Reference laboratory. If the confirmatory testing comes back negative, the sample is cleared. We propose to amend paragraph (c)(1) so that the testing would instead have to find no *M. Gallisepticum* infected birds.

Paragraph (d)(5) of § 145.43 contains a typo that we would correct; it refers to "block" when contextually "flock" is meant.

Section 145.53 sets forth terminology and classification provisions for hobbyist and exhibition poultry, as well as raised-for-release waterfowl, breeding flocks and their products. Within the section, paragraph (e) contains provisions for a U.S. H5/H7 Avian Influenza Clean classification for such poultry and products. That paragraph currently states that the classification pertains to hobbyist or exhibition waterfowl, exhibition poultry, and game bird poultry and products. However, as noted above, the section does not pertain to exhibition waterfowl or game birds. We propose to amend paragraph

(e) accordingly to remove such references.

Section 145.73 sets forth terminology and classification provisions for egg-type chicken breeding flocks and their products. Paragraph (d) contains provisions for U.S. *S. Enteritidis* Clean classification for such flocks and products. Within paragraph (d), paragraph (d)(1)(i) currently requires either that a flock originates from a U.S. *S. Enteritidis* Clean flock, or meconium from the chick boxes and a sample of chicks that died within 7 days after hatching are examined bacteriologically for salmonella at an authorized laboratory, and cultures from positive samples are serotyped, as a condition of classification. Contextually, the paragraph is referring to samples that are positive for serogroup D of salmonella. We propose to revise the paragraph to make it clear that this was the relevant serogroup being referenced.

Paragraph (g) of § 145.73 contains provisions for U.S. *Salmonella* Monitored status for egg-type chicken breeding flocks and their products, while paragraph (f) of § 145.83 contains provisions for primary meat-type breeding flocks and their products. In both sections of the regulations, we currently require, among other things, that an Authorized Agent take environmental samples from each flock at 4 months of age and every 30 days thereafter; that an authorized laboratory for *Salmonella* examine the environmental samples bacteriologically; and that all *Salmonella* isolates from a flock be serogrouped and be reported to the Official State Agency on a monthly basis. As we mentioned previously in this document, environmental testing is not the same as flock testing, and positive samples within the environment do not necessarily mean the flock itself is infected. For those reasons, reporting the results of all testing to the Official State Agency on a monthly basis is not warranted. For a monitoring program, the Official State Agency need only know whether the *Salmonella* is present or absent in the flocks themselves. We would amend the two sections accordingly. We would also remove references in paragraph (g) of § 145.73 and paragraph (f) of § 145.83 which could be read to suggest that the above testing is flock testing, rather than environmental testing.

Paragraph (f) of § 145.83 also provides that any flock entering the production period that is in compliance with all the paragraph, and with no history of *Salmonella* isolations, shall be considered “*Salmonella* negative” and may retain this definition as long as no

environmental or bird *Salmonella* isolations are identified and confirmed from the flock or flock environment by sampling on four separate collection dates over a minimum of a 2-week period. We are proposing to revise the minimum 2-week period to a maximum 4-week period.

For flocks in production, it is common to have hatching eggs set aside in hatcheries for customer orders. If salmonella isolation occurs, confirmatory testing must be timely so that a business decision can be made regarding the disposition of the eggs. Allowing four sets of confirmatory samples over a four-week period provides sufficient time for sampling to occur while not allowing the sampling interval to be open-ended, as is currently the case.

Proposed Revisions to Part 147

In § 147.52, the regulations state the minimum requirements for an APHIS authorized laboratory evaluation to ensure that they are in compliance with NPIP regulations. Paragraph (f) of that section contains reporting requires for authorized laboratories. Within that paragraph, paragraph (f)(2) currently requires *Salmonella pullorum* and *Mycoplasma* Plan disease reactors to be reported to the Official State Agency within 48 hours. However, as noted above, a reactor, by definition, is not an infected sample. Rather, it is a sample that is sent to an authorized laboratory for confirmatory testing to determine whether it is infected with disease. Accordingly, we would revise paragraph (f)(2) to require reporting of infected flocks, rather than reactors.

Proposed Revisions to NPIP Program Standards

We have also prepared updates to the NPIP Program Standards document. The proposed updates would amend several sections of the document.

We would revise the definitions section in the Program Standards document by:

- Amending the definition of *hatchery and multiplier breeding flock*;
- Clarifying the definition of *reactor*;
- Revising the *Salmonella Pullorum*, *Gallinarum* and *Enteritidis* nomenclature.

These changes would help ensure that the Program Standards are aligned with our proposed revisions to the regulations themselves.

We would revise section A, “Blood Testing Procedures,” by removing the description of how standard tube agglutination test containers should be constructed in order to be used; the current language is overly prescriptive

in a manner that is not necessary for purposes of ensuring the containers can validly be used for blood testing procedures.

We would revise section B, “Bacteriological Examination Procedures,” by:

- Clarifying environmental samples are not for use to qualify or test flocks for PT Clean classification. As discussed previously in this document, environmental sampling and flock testing are distinct activities.

- Clarifying dilutions and volume of enrichment broth for the isolation and identification of *Salmonella*. The current language is overly prescriptive depending on the method of dilution used.

- Allowing a temperature range for incubation and enrichment broth and pre-enrichment broth for isolation and identification of *Salmonella*. The current standard specifies a specific temperature but a range in tolerance of temperatures is scientifically justified and consistent with international standards.

- Clarifying isolation and identification procedures for *Salmonella* by adding molecular procedures to Illustration 2. The proposed change to Illustration 2 provides visualization of the confirmation procedures.

- Removing the Hajna or Muller-Kauffmann reference for selective enrichment broth for lab procedure for bacteriological examination of cull chicks and poults for *Salmonella*. This change is being proposed to establish a more generalized protocol rather than confining laboratories to using just two specific types of Tetrathionate broth selective enrichment.

We would revise section D, “Molecular Examination Procedures,” by:

- Clarifying the PCR grade water to use for re-suspension of the pellet before boiling in the lab procedures for PCR testing for MG and MS.

- Adding *Salmonella* spp. qPCR to the list of approved molecular examination procedures
- Adding new diagnostic tests to the approved molecular examination procedures.

We would revise section E, “Biosecurity Principles,” to include provisions referenced in our above discussion of the proposed revisions to § 56.10.

In addition, in § 147.53 of the regulations, we set forth the process for updating the approved tests and sanitation procedures located in the Program Standards document. In that section, we indicate that when the Administrator approves a new test or

sanitation procedure or a change to an existing test or sanitation procedure, APHIS will publish a notice in the **Federal Register** making available the test or sanitation procedure, and that this notice will take public comment. With regard to proposed changes to an existing test or sanitation procedure, it is our intent that in the future we would only seek public comment through a **Federal Register** notice when the change would be a substantive change to the test or sanitation procedure that materially changes how the existing test or sanitation procedure is to be conducted. If the changes are non-substantive clarifications or remove strictures to allow for additional means of conducting the procedure, this change would not follow the process set forth in § 147.53 of the regulations and would be communicated to the public through other means available to the Agency. We feel public comment through a **Federal Register** notice is not warranted in these situations because parties following the existing procedures would be able to continue to do so.

Updates to Control Numbers

Finally, we are updating the Office of Management and Budget (OMB) control numbers for certain sections to reflect that OMB control number 0579–0474 expired and the associated paperwork burden (the reporting, recordkeeping, and third-party disclosure requirements) was added to OMB control number 0579–0007. In addition, where necessary, we are also adding reference to OMB control number 0579–0440.

Executive Orders 12866 and Regulatory Flexibility Act

This proposed rule has been determined to be not significant for the purposes of Executive Order 12866 and, therefore, has not been reviewed by the Office of Management and Budget.

This rulemaking would result in various changes to regulations in 9 CFR parts 56, and 145 through 147, modifying provisions of the NPIP. The modifications are recommended by the NPIP General Conference Committee (GCC), which represents cooperating State agencies and poultry industry members and advises the Secretary on issues pertaining to poultry health. These amendments would, among other things, condition indemnity for low pathogenicity avian influenza on adherence to biosecurity plans, clarify existing provisions of the regulations, fix editorial errors, and align the regulations more closely with current producer practices.

These changes would align the regulations with international standards and make them more transparent to APHIS stakeholders and the general public. The changes included in this proposed rule were voted on and approved by the voting delegates at the Plan's 2022 Biennial Conference.

The establishments that would be affected by this rulemaking—principally entities engaged in poultry production and processing—are predominantly small by Small Business Administration standards. In those instances in which an addition or modification could potentially result in a cost to certain entities, we do not expect the costs to be significant. This proposed rule embodies changes decided upon by the NPIP GCC on behalf of Plan members, that is, changes recognized by the poultry industry as in their interest. We note that NPIP membership is voluntary.

Under these circumstances, the Administrator of the Animal and Plant Health Inspection Service has determined that this action, if promulgated, will not have a significant economic impact on a substantial number of small entities.

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 proposed rule has been reviewed under Executive Order 12988, Civil Justice Reform. If this proposed rule is adopted: (1) All State and local laws and regulations that are in conflict with this rule will be preempted; (2) no retroactive effect will be given to this rule; and (3) administrative proceedings will not be required before parties may file suit in court challenging this rule.

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 proposed rule are currently approved by the Office of Management and Budget (OMB) under OMB control numbers 0579–0007 and 0579–0440.

E-Government Act Compliance

The Animal and Plant Health Inspection Service is committed to compliance with the E-Government 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 proposed rule, please contact Mr. Joseph Moxey, APHIS' Information Collection Coordinator, at (301) 851–2533.

List of Subjects

9 CFR Part 56

Animal diseases, Indemnity payments, Low pathogenic avian influenza, Poultry.

9 CFR Parts 145, 146, and 147

Animal diseases, Poultry and poultry products, Reporting and recordkeeping requirements.

Accordingly, we propose to amend 9 CFR parts 56, 145, 146, and 147 as follows:

PART 56—CONTROL OF H5/H7 LOW PATHOGENIC AVIAN INFLUENZA

- 1. The authority citation for part 56 continues to read as follows:

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

- 2. Amend § 56.1 by:

- a. Adding in alphabetical order a definition for “National Poultry Improvement Plan (NPIP) Program Standards”; and

- b. Revising the definition for “Virus elimination (VE)”.

The addition and revision read as follows:

§ 56.1 Definitions.

* * * * *

National Poultry Improvement Plant (NPIP) Program Standards. A document that contains tests and sanitation procedures approved by the Administrator pursuant to § 147.53 of this chapter. This document may be obtained from the National Poultry Improvement Plan website at <http://www.poultryimprovement.org/> or by writing to the Service at National Poultry Improvement Plan, APHIS, USDA, 1506 Klondike Road, Suite 301, Conyers, GA 30094.

* * * * *

Virus elimination (VE). Cleaning and disinfection or other measures conducted to destroy or eliminate all AI virus on the premises.

- 3. Amend § 56.2 by adding an OMB citation at the end of the section to read as follows:

§ 56.2 Cooperation with States.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0440)

■ 4. Amend § 56.3 by revising paragraphs (a)(3) and (b) and adding an OMB citation at the end of the section to read as follows:

§ 56.3 Payment of indemnity and/or compensation.

(a) * * *

(3) Virus elimination (VE) measures taken on premises, conveyances, and materials that came into contact with poultry that were infected with or exposed to H5/H7 LPAI; or, in the case of materials, if the cost of the VE measures would exceed the value of the materials or the VE measures would be impracticable for any reason, the destruction and the disposal of the materials.

(b) *Percentage of costs eligible for indemnity and/or compensation.* The Administrator is authorized to pay 100 percent of the costs and/or compensation, as determined in accordance with § 56.4, of the activities described in paragraphs (a)(1) through (3) of this section, provided that the conditions in paragraph (b)(1) or (2) of this section apply. For infected or exposed poultry that are not described in the categories below, the Administrator is authorized to pay 25 percent of the costs of the activities described in paragraphs (a)(1) through (3) of this section:

(1)(i) The poultry are from:

(A) A commercial table-egg laying premises with at least 75,000 birds; or

(B) A meat-type chicken slaughter plant that slaughters at least 200,000 meat-type chickens in an operating week; or

(C) A meat-type turkey slaughter plant that slaughters at least 2 million meat-type turkeys in a 12-month period; or

(D) A meat-type game bird and waterfowl slaughter plant that slaughters at least 50,000 birds annually; or

(E) A raised-for-release game bird premises, raised-for-release waterfowl premises, and egg-type game bird or waterfowl producing eggs for human consumption premises that raise at least 25,000 birds annually and have at least 5,000 birds onsite; or

(F) A breeder flock premises with at least 5,000 birds; and

(ii) The breeding flock, commercial flock, or slaughter plant participates in the U.S. Avian Influenza Clean, H5/H7 Avian Influenza Clean, or U.S. H5/H7 Avian Influenza Monitored program of the Plan available to the flock in part 145 or 146 of this chapter; and

(iii) The owner of the poultry or eggs, and, if applicable, any party that enters

into a contract with the owner to grow or care for the poultry or eggs had in place and was following a biosecurity plan that is in compliance with biosecurity principles approved by the Administrator (within the National Poultry Improvement Plan (NPIP) Program Standards, Standard E pertains to Biosecurity Principles) and has been audited for the Official State Agency to ensure that the biosecurity plan is in compliance at the time of detection of H5/H7 LPAI.

(2) The flock does not meet the size requirements as described in paragraph (b)(1) of this section, regardless of whether the infected or exposed poultry participate in the Plan.

(3) The Administrator is authorized to pay 25 percent of the costs and/or compensation, as determined in accordance with § 56.4, of the activities described in paragraphs (a)(1) through (3) of this section, for flocks that:

(i) Do not meet the conditions described in paragraph (b)(1) or (2) of this section; or

(ii) The poultry are located in a State that does not participate in the diagnostic surveillance program for H5/H7 LPAI, as described in § 146.14 of this chapter, or that does not have an initial State response and containment plan for H5/H7 LPAI that is approved by APHIS under § 56.10, unless such poultry participate in the Plan with another State that does participate in the diagnostic surveillance program for H5/H7 LPAI, as described in § 146.14 of this chapter, and has an initial State response and containment plan for H5/H7 LPAI that is approved by APHIS under § 56.10, unless such poultry participate in the Plan with another State that does participate in the diagnostic surveillance program for H5/H7 LPAI, as described in § 146.14 of this chapter, and has an initial State response and containment plan for H5/H7 LPAI that is approved by APHIS under § 56.10.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0440)

■ 5. Amend § 56.4 by revising the OMB citation at the end of the section to read as follows:

§ 56.4 Determination of indemnity and/or compensation amounts.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0007 and 0579–0440)

■ 6. Amend § 56.5 by:

■ a. Redesignating paragraphs (c)(1)(ii) through (iv) as paragraphs (c)(1)(iii) through (v), respectively, and adding a new paragraph (c)(1)(ii);

■ b. Revising newly redesignated paragraph (c)(1)(iv); and

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

The additions and revision read as follows:

§ 56.5 Destruction and disposal of poultry and cleaning and disinfection (virus elimination) of premises, conveyances, and materials.

* * * * *

(c) * * *

(1) * * *

(ii) Poultry will be monitored daily for the development of additional and/or increased severity of clinical signs with scheduled flock observation, tracking, and recording flock(s) mortality, taking action as directed by the Official State Agency.

* * * * *

(iv) Routes to slaughter must avoid other commercial poultry operations whenever possible. All load-out equipment, trailers, and trucks used on the premises that have housed poultry that were infected with or exposed to H5/H7 LPAI must undergo virus elimination procedures and not enter other poultry premises or facilities for 48 hours after the virus elimination procedures have been completed.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0440)

■ 7. Amend § 56.6 by revising the OMB citation at the end of the section to read as follows:

§ 56.6 Presentation of claims for indemnity and/or compensation.

* * * * *

(Approved by the Office of Management and Budget under control numbers 0579–0007 and 0579–0440)

■ 8. Section 56.10 is revised and republished to read as follows:

§ 56.10 Initial State response and containment plan.

(a) In order for poultry owners within a State to be eligible for indemnity and/or compensation for 100 percent of eligible costs under § 56.3(b), the State in which the poultry participate in the Plan must have in place an initial State response and containment plan that has been approved by APHIS. The initial State response and containment plan must be developed by the Official State Agency. In States where the Official State Agency is different than the Cooperating State Agency, the

Cooperating State Agency must also participate in the development of the plan. The plan must be administered by the Cooperating State Agency of the relevant State. This plan must include:

(1) Provisions for a standing emergency disease management committee, regular meetings, and exercises, including coordination with any Tribal governments that may be affected;

(2) A biosecurity plan for poultry owners based on their flock size as stated in § 56.3 and, if applicable, any party that enters into a contract with the owner to grow or care for the poultry or eggs that had in place and was following a biosecurity plan that was audited by the Official State Agency to ensure that the biosecurity plan was in compliance according to the Program Standards, Standard E pertaining to the Biosecurity Principles as approved by the Administrator;

(3) Provisions for adequate diagnostic resources;

(4) Detailed, specific procedures for initial handling and investigation of suspected cases of H5/H7 LP AI;

(5) Detailed, specific procedures for reporting test results to APHIS. These procedures must be developed after appropriate consultation with poultry producers in the State and must provide for the reporting only of confirmed cases of H5/H7 LP AI in accordance with § 146.13 of this chapter;

(6) Detailed, strict quarantine measures for presumptive and confirmed index cases;

(7) Provisions for developing flock plans for infected and exposed flocks;

(8) Detailed plans for disposal of infected flocks, including preexisting agreements with regulatory agencies and detailed plans for carcass disposal, disposal sites, and resources for conducting disposal, and detailed plans for disposal of materials that come into contact with poultry infected with or exposed to H5/H7 LP AI;

(9) Detailed plans for cleaning and disinfection of premises, repopulation, and monitoring after repopulation;

(10) Provisions for appropriate control/monitoring zones, contact surveys, and movement restrictions;

(11) Provisions for monitoring activities in control zones;

(12) If vaccination is considered as an option, a written plan for use in place with proper controls and provisions for APHIS approval of any use of vaccine;

(13) Plans for H5/H7 LP AI-negative flocks that provide for quarantine, testing, and controlled marketing; and

(14) Public awareness and education programs regarding avian influenza.

(b) If a State is designated a U.S. Avian Influenza Monitored State, Layers under § 146.24(a) of this chapter or a U.S. Avian Influenza Monitored State, Turkeys under § 146.44(a) of this chapter, it will lose that status during any outbreak of H5/H7 LP AI and for 90 days after the destruction and disposal of all infected or exposed birds and cleaning and disinfection of all affected premises are completed.

(Approved by the Office of Management and Budget under control numbers 0579-0007 and 0579-0440)

PART 145—NATIONAL POULTRY IMPROVEMENT PLAN FOR BREEDING POULTRY

■ 9. The authority citation for part 145 continues to read as follows:

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

■ 10. Amend part 145 by:

■ a. Removing “*S. gallinarum*” wherever it appears and adding “*Salmonella Gallinarum*” in its place;

■ b. Removing “*S. pullorum*” wherever it appears and adding “*Salmonella Pullorum*” in its place;

■ c. Removing “*S. enteritidis*” and “*Salmonella enteritidis ser enteritidis*” wherever they appear and adding “*Salmonella Enteritidis*” in its place.

■ 11. Amend § 145.1 by:

■ a. Revising the definition of “Fowl typhoid or typhoid”;

■ b. In the definition for “Hatchery”, adding the words “and/or embryonated eggs” after the words “baby poultry”;

■ c. In the definition for “Multiplier breeding flock”, removing the word “hatching” and adding the word “fertile” in its place;

■ d. Revising the definition of “Pullorum disease or pullorum”;

■ e. In the definition for “Reactor”, adding a sentence after the last sentence; and

■ f. Adding in alphabetical order a definition for “*Salmonella Enteritidis*”.

The revisions and additions read as follows:

§ 145.1 Definitions.

* * * * *

Fowl typhoid or typhoid. A disease of poultry caused by *Salmonella enterica*

subspecies *enterica* serovar *Gallinarum* biovar *Gallinarum* (*Salmonella Gallinarum*).

* * * * *

Pullorum disease or pullorum. A disease of poultry caused by *Salmonella enterica* subspecies *enterica* serovar *Gallinarum* biovar *Pullorum* (*Salmonella Pullorum*).

Reactor. * * * A reactor is considered suspect until additional confirmatory testing has been conducted by an authorized laboratory or Federal Reference Laboratory as outlined in § 145.14.

* * * * *

Salmonella Enteritidis. A bacteria found in poultry caused by *Salmonella enterica* subspecies *enterica* serovar *Enteritidis* (*Salmonella Enteritidis*).

* * * * *

§ 145.2 [Amended]

■ 12. Amend § 145.2 in paragraph (d) by removing the citation “§ 145.3(e)” and adding the citation “§ 145.3(f)” in its place.

§ 145.5 [Amended]

■ 13. Amend § 145.5 in paragraph (c) by removing the text “Subparts B, C, D, E, F, G, H, or I” and adding the text “Subpart B, C, D, E, F, G, H, I or J” in its place.

■ 14. Amend § 145.10 by:

■ a. In paragraph (b) introductory text, removing the text “and 145.93(b)” and adding the text “145.93(b), and 145.103(b)” in its place;

■ b. In paragraph (g) introductory text, removing the text “and 145.94(a)” and adding the text “145.94(a), and 145.104(a)” in its place;

■ c. In paragraph (o) introductory text, removing the text “and 145.93(d)” and adding the text “145.93(d), and 145.103(d)” in its place;

■ d. In paragraph (t) introductory text, removing the text “and 145.93(c)” and adding the text “145.93(c), and 145.103(c)” in its place; and

■ e. Adding paragraphs (u), (v), and (w).

The additions read as follows:

§ 145.10 Terminology and classification; flocks, products, and States.

* * * * *

(u) *U.S. Newcastle Clean.* (See §§ 145.43(h), 145.73(h), and 145.83(h).)

BILLING CODE 3410-34-P

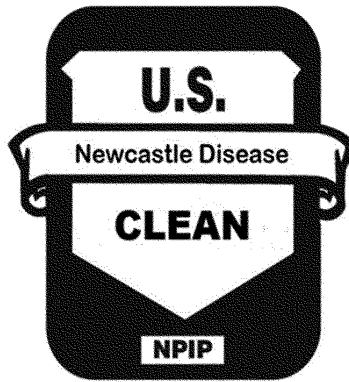


FIGURE 22

(v) *U.S. Avian Influenza Clean Compartment.* (See §§ 145.45, 145.74, and 145.84.)

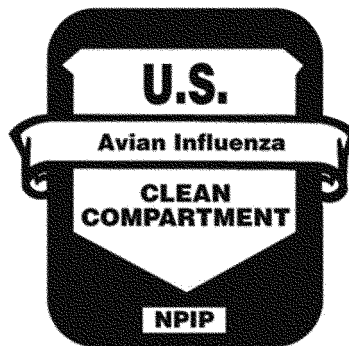


FIGURE 23

(w) *U.S. Newcastle Disease Clean Compartment.* (See §§ 145.45, 145.74, and 145.84.)



FIGURE 24

BILLING CODE 3410-34-C

■ 15. Amend § 145.14 by:

- a. Revising the introductory text;
- b. In paragraph (a)(1), adding the text “(within the Program Standards document, Program Standard A applies to blood testing; alternatives to the program standards may also be approved by the Administrator under § 145.73 of this chapter)” after the word “subchapter” in the second sentence;
- c. In paragraph (a)(5), removing the text “and 145.93” and adding the text “145.93, and 145.103” in its place; and
- d. Revising paragraph (a)(6)(ii).

The revisions read as follows:

§ 145.14 Testing.

Poultry must be more than 4 months of age when tested for an official classification: *Provided*, That turkey candidates under subpart D of this part may be tested at more than 12 weeks of age; game bird candidates under subpart E or subpart J of this part may be tested when more than 4 months of age or upon reaching sexual maturity, whichever comes first; and ostrich, emu, rhea, and cassowary candidates under subpart F of this part may be tested when more than 12 months of age. Samples for official tests shall be collected by an Authorized Agent, Authorized Testing Agent, or State Inspector and tested by an authorized laboratory, except that the stained antigen, rapid whole-blood test for pullorum-typhoid may be conducted by an Authorized Testing Agent or State Inspector. Testing must be conducted as specified within the Subpart Plan program, with at least 1 bird tested from each pen and unit in the house and a minimum of 30 birds tested per house. The ratio of samples collected from male and female birds must be representative of birds throughout the house and flock. In houses containing fewer than 30 birds other than ostriches, emus, rheas, and cassowaries, all birds in the house must be tested, unless otherwise specified within the Plan program.

- (a) * * *
- (6) * * *

(ii) Reactors to the standard tube agglutination test (in dilutions of 1:50 or greater) or the microagglutination test (in dilutions of 1:40 or greater) shall be submitted to an authorized laboratory for bacteriological examination. If there are more than four reactors in a flock, a minimum of four reactors shall be submitted to the authorized laboratory; if the flock has four or fewer reactors, all of the reactors must be submitted. Bacteriological examination must be conducted in accordance with part 147 of this subchapter (within the Program

Standards document, Program Standard B addresses bacteriological examination procedures; alternatives to the program standards may also be approved by the Administrator under § 145.73). When reactors are submitted to the authorized laboratory within 10 days of the date of reading an official blood test named in paragraph (a)(6)(i) of this section, and the bacteriological examination fails to demonstrate pullorum-typhoid infection, the Official State Agency shall presume that the flock is determined not to be infected with *Salmonella* Pullorum or *Salmonella* Gallinarum.

* * * * *

■ 16. Amend § 145.33 by:

- a. Removing the semicolon after paragraph (d)(1)(vii) and adding a period in its place;
- b. Removing paragraph (d)(1)(viii);
- c. Adding paragraph (l)(1)(iv);
- d. Removing and reserving paragraph (l)(2);
- e. In paragraph (m)(2)(i), adding the words “by the company” after the words “shall be conducted”; and
- f. Removing and reserving paragraphs (m)(2)(ii) through (iv).

The addition reads as follows:

§ 145.33 Terminology and classification; flocks and products.

* * * * *

(l) * * *

(1) * * *

(iv) Fifteen (15) birds are tested and found negative for avian influenza within 21 days prior to movement to slaughter regardless of the date of the previous test.

* * * * *

■ 17. Amend § 145.43 by:

- a. Revising paragraph (c)(1);
- b. In paragraph (d)(1)(i), adding the words “or 60 samples, from mixed male and female flocks, (the ratio of samples collected from male and female birds must be representative of birds throughout the house)” after the words “from female flocks”;
- c. Adding a reserved paragraph (d)(1)(ii);
- d. In paragraph (d)(5), removing the word “block” and adding the word “flock” in its place;
- e. In paragraph (e)(1), adding the words “or 60 samples, from mixed male and female flocks, (the ratio of samples collected from male and female birds must be representative of birds throughout the house)” after the words “from female flocks” in the first sentence;
- f. Removing paragraph (f)(5) and redesignating paragraphs (f)(6) and (7) as paragraphs (f)(5) and (6);
- g. Revising paragraph (h)(3)(i);

- h. Removing paragraph (h)(3)(ii) and redesignating paragraph (h)(3)(iii) as paragraph (h)(3)(ii); and
- i. Revising the OMB citation at the end of the section.

The revisions and addition read as follows:

§ 145.43 Terminology and classification; flocks and products.

* * * * *

(c) * * *

(1) A flock maintained in accordance with part 147 of this subchapter with respect to Mycoplasma isolation, sanitation, and management, and in which no *M. Gallisepticum* infected birds are found when a random sample of at least 10 percent of the birds in the flock, or 300 birds in flocks of more than 300 and each bird in flocks of 300 or less, is tested when more than 12 weeks of age, in accordance with the procedures described in § 145.14(b); *Provided*, that to retain this classification, a minimum of 30 samples from male flocks and 60 samples from female flocks or 60 samples from mixed, male and female flocks, (the ratio of samples collected from male and female birds must be representative of birds throughout the house), shall be retested at 28–30 weeks of age and at 4–6 week intervals thereafter.

* * * * *

(d) * * *

(1) * * *

(ii) [Reserved]

* * * * *

(h) * * *

(3) * * *

(i) A minimum of 30 birds per flock must test negative using an approved test in § 145.14 at intervals of 90 days or a sample of fewer than 30 birds may be tested, and found negative, at any one time if all pens are equally represented and a total of 30 birds is tested within each 90-day period; and

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0007)

- 18. Amend § 145.45 by revising the OMB citation at the end of the section to read as follows:

§ 145.45 Terminology and classification; compartments.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0007)

§ 145.53 [Amended]

- 19. Amend § 145.53 in paragraph (e) introductory text by removing the words “hobbyist or exhibition waterfowl, exhibition poultry, and game bird” and adding the words “hobbyist and exhibition poultry, and raised-for-

release waterfowl” in their place in the second sentence.

■ 20. Amend § 145.73 by:

- a. In paragraph (d)(1)(i), adding the words “serogroup D” after the words “Cultures from” in the last sentence;
- b. In paragraph (g)(1)(v), removing the words “and shall be reported to the Official State Agency on a monthly basis” and adding a sentence at the end of the paragraph;
- c. In paragraph (g)(1)(vi), removing the words “to allow for the serological testing required under paragraph (g)(1)(iv) of this section” and adding the words “to allow for serological testing” in their place;
- d. Revising paragraph (h)(3)(i);
- e. Removing paragraph (h)(3)(ii) and redesignating paragraph (h)(3)(iii) as paragraph (h)(3)(ii); and
- f. Revising the OMB citation at the end of the section.

The addition and revisions read as follows:

§ 145.73 Terminology and classification; flocks and products.

* * * * *

(g) * * *

(1) * * *

(v) * * * Owners of flocks shall report the presence or absence of *Salmonella* in their flocks on a monthly basis to the Official State Agency.

* * * * *

(h) * * *

(3) * * *

(i) A minimum of 30 birds per flock must test negative using an approved test in § 145.14 at intervals of 90 days or a sample of fewer than 30 birds may be tested, and found negative, at any one time if all pens are equally represented and a total of 30 birds is tested within each 90-day period; and

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0007)

■ 21. Amend § 145.74 by revising the OMB citation at the end of the section to read as follows:

§ 145.74 Terminology and classification; compartments.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0007)

■ 22. Amend § 145.83 by:

- a. In paragraph (e)(6)(i)(C), removing the words “*Salmonella pullorum*” and adding the words “*Salmonella Pullorum*” in their place in the first sentence;
- b. In paragraph (f)(1)(iv), revising the third sentence and adding a sentence at the end of the paragraph;
- c. In paragraph (f)(1)(v), removing the words “to allow for the serological

testing required under paragraph (f)(1)(iv) of this section” and adding the words “to allow for serological testing” in their place;

■ d. In paragraph (f)(1)(vi), removing the words “minimum of a 2-week period” and adding the words “maximum of a 4-week period” in their place in the first sentence;

■ e. Revising paragraph (h)(3)(i);

■ f. Removing paragraph (h)(3)(ii) and redesignating paragraph (h)(3)(iii) as paragraph (h)(3)(ii); and

■ g. Revising the OMB citation at the end of the section.

The addition and revisions read as follows:

§ 145.83 Terminology and classification; flocks and products.

* * * * *

(f) * * *

(1) * * *

(iv) * * * All *Salmonella* isolates from a flock shall be serogrouped.

Owners of flocks shall report the presence or absence of *Salmonella* in their flocks on a monthly basis to the Official State Agency;

* * * * *

(h) * * *

(3) * * *

(i) A minimum of 30 birds per flock must test negative using an approved test in § 145.14 at intervals of 90 days or a sample of fewer than 30 birds may be tested, and found negative, at any one time if all pens are equally represented and a total of 30 birds is tested within each 90-day period; and

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0007)

■ 23. Amend § 145.84 by:

■ a. In paragraph (a)(3)(iii), adding the words “and/or ND Clean” after the words “Influenza Clean”; and

■ b. Revising the OMB citation at the end of section.

The revision reads as follows:

§ 145.84 Terminology and classification; compartments.

* * * * *

(Approved by the Office of Management and Budget under control number 0579–0007)

■ 24. Amend § 145.102 by revising paragraph (e) to read as follows:

§ 145.102 Participation.

* * * * *

(e) Under this subpart, gallinaceous flocks and waterfowl flocks may not be raised on the same premises. If they are on the same premises, they must be registered under subpart E of this part.

* * * * *

§ 145.103 [Amended]

■ 25. Amend § 145.103 in paragraph (b)(3) introductory text by removing the words “to reveal Pullorum-Typhid” and adding the words “to reveal Pullorum-Typhoid” in their place.

PART 146—NATIONAL POULTRY IMPROVEMENT PLAN FOR COMMERCIAL POULTRY

■ 26. The authority citation for part 146 continues to read as follows:

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

■ 27. Amend part 146 by:

- a. Removing “*S. gallinarum*” wherever it appears and adding “*Salmonella Gallinarum*” in its place;
- b. Removing “*S. pullorum*” wherever it appears and adding “*Salmonella Pullorum*” in its place;
- c. Removing “*S. enteritidis*” and “*Salmonella enteritidis ser enteritidis*” wherever they appear and adding “*Salmonella Enteritidis*” in its place.

§ 146.3 [Amended]

■ 28. Amend § 146.3 by:

- a. In paragraph (a), removing the words “raised-for-release upland game bird premises, and raised-for-release waterfowl premises and any commercial upland game bird, commercial waterfowl” and adding the words “egg/meat-type game bird, egg/meat-type waterfowl” in their place; and
- b. In paragraph (c), removing the words “commercial upland gamebird, commercial waterfowl” and adding the words “egg/meat-type game bird, egg/meat-type waterfowl” in their place in the first sentence.

§ 146.6 [Amended]

■ 29. Amend § 146.6 by:

- a. In paragraph (a), removing the words “commercial upland game bird, commercial waterfowl” and adding the words “meat-type game bird, meat-type waterfowl” in their place; and
- b. In paragraph (b), removing the words “commercial upland game bird and commercial waterfowl” and adding the words “meat-type game bird and meat-type waterfowl” in their place.

§ 146.9 [Amended]

■ 30. In § 146.9 in paragraph (a) introductory text by removing the text “and (b)”.

Subpart E—Special Provisions for Egg/Meat-Type Game Birds, Egg/Meat-Type Waterfowl, Meat-Type Game Bird Slaughter Plants, and Meat-Type Waterfowl Slaughter Plants

■ 31. Revise the subpart E heading to read as set forth above.

PART 147—AUXILIARY PROVISIONS ON NATIONAL POULTRY IMPROVEMENT PLAN

■ 32. The authority citation for part 147 continues to read as follows:

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

■ 33. Amend part 147 by:

- a. Removing “*S. gallinarum*” wherever it appears and adding “*Salmonella Gallinarum*” in its place;
 - b. Removing “*S. pullorum*” wherever it appears and adding “*Salmonella Pullorum*” in its place;
 - c. Removing “*S. enteritidis*” and “*Salmonella enteritidis* ser *enteritidis*” wherever they appear and adding “*Salmonella Enteritidis*” in its place.
- 34. Amend § 147.46 by revising paragraph (a)(9) to read as follows:

§ 147.46 Committee consideration of proposed changes.

(a) * * *

(9) Egg/meat-type game birds and waterfowl.

* * * * *

■ 35. Amend § 147.52 by revising paragraph (f)(2) to read as follows:

§ 147.52 Authorized laboratories.

* * * * *

(f) * * *

(2) All *Salmonella Pullorum* and *Mycoplasma Plan* disease infected flocks as confirmed by testing in accordance with § 145.14 must be reported to the Official State Agency within 48 hours.

* * * * *

Done in Washington, DC, this 3rd day of June 2024.

Michael Watson,

Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 2024–12659 Filed 6–10–24; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2024–1650; Airspace Docket No. 24–ANE–6]

RIN 2120–AA66

Amendment of Class E Airspace; Claremont, NH

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This action proposes to amend Class E airspace extending

upward from 700 feet above the surface for Claremont Municipal Airport, Claremont, NH, as the Claremont Non-directional Beacon (NDB) has been decommissioned and associated instrument approaches canceled. Controlled airspace is necessary for the safety and management of instrument flight rules (IFR) operations at this airport.

DATES: Comments must be received on or before July 26, 2024.

ADDRESSES: Send comments identified by FAA Docket No. FAA–2024–1650 and Airspace Docket No. 24–ANE–06 using any of the following methods:

* *Federal eRulemaking 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 for 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 the 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 for Federal holidays.

FAA Order JO 7400.11H Airspace Designations and Reporting Points and subsequent amendments can be viewed online at www.faa.gov/air_traffic/publications/. You may also contact the Rules and Regulations Group, Office of Policy, Federal Aviation Administration, 800 Independence Avenue SW, Washington, DC 20591; telephone: (202) 267–8783.

FOR FURTHER INFORMATION CONTACT: John Fornito, Operations Support Group, Eastern Service Center, Federal Aviation Administration, 1701 Columbia Ave., College Park, GA 30337; telephone (404) 305–6364.

SUPPLEMENTARY INFORMATION:

Authority for This Rulemaking

The FAA’s authority to issue rules regarding aviation safety is found in Title 49 of the United States Code.

Subtitle I, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency’s authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority, as it would amend Class E airspace extending upward from 700 feet above the surface at Claremont Municipal Airport, Claremont, NH, to support standard instrument approach procedures for IFR operations at this airport.

Comments Invited

The FAA invites interested persons to participate in this rulemaking by submitting written comments, data, or views. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. To ensure the docket does not contain duplicate comments, commenters should submit only one time if comments are filed electronically, or commenters should send only one copy of written comments if comments are filed in writing.

The FAA will file in the docket all comments it receives, as well as a report summarizing each substantive public contact with FAA personnel concerning this proposed rulemaking. Before acting on this proposal, the FAA will consider all comments it receives on or before the closing date for comments. The FAA will consider comments filed after the comment period has closed if it is possible to do so without incurring expense or delay. The FAA may change this proposal in light of the comments it receives.

Privacy: In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better 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.

Availability of Rulemaking Documents

An electronic copy of this document may be downloaded through the

internet at www.regulations.gov. Recently published rulemaking documents can also be accessed through the FAA's web page at www.faa.gov/air-traffic/publications/airspace_amendments/.

You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Operations office (see **ADDRESSES** section for address, phone number, and hours of operations). An informal docket may also be examined during regular business hours at the office of the Eastern Service Center, Federal Aviation Administration, Room 210, 1701 Columbia Ave., College Park, GA 30337.

Incorporation by Reference

Class E airspace designations are published in Paragraphs 6005 of FAA Order JO 7400.11, Airspace Designations and Reporting Points, which is incorporated by reference in 14 CFR 71.1 on an annual basis. This document proposes to amend the current version of that order, FAA Order JO 7400.11H, dated August 11, 2023, and effective September 15, 2023. These updates will be published in the next update to FAA Order JO 7400.11. That order is publicly available as listed in the **ADDRESSES** section of this document.

FAA Order JO 7400.11H lists Class A, B, C, D, and E airspace areas, air traffic service routes, and reporting points.

The Proposal

The FAA proposes an amendment to 14 CFR part 71 to amend Class E airspace extending upward from 700 feet above the surface within a 7.3-mile radius (previously 5.5 miles) of Claremont Municipal Airport, Claremont, NH, and within 2 miles on each side of the 093° bearing of the airport, extending from the 7.3-mile radius to 15.1 miles east of the airport. An airspace evaluation caused this action due to the decommissioning of the Claremont NDB. The increased radius would encompass the remaining instrument approaches into this airport. Controlled airspace is necessary for the safety and management of instrument flight rules (IFR) operations in the area.

Regulatory Notices and Analyses

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a “significant regulatory action” under Executive Order 12866; (2) is not a “significant rule” under Department of

Transportation (DOT) Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this proposed rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

Environmental Review

This proposal would be subject to an environmental analysis in accordance with FAA Order 1050.1F, “Environmental Impacts: Policies and Procedures,” prior to any FAA final regulatory action.

Lists of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

In consideration of the foregoing, the Federal Aviation Administration proposes to amend 14 CFR part 71 as follows:

PART 71—DESIGNATION OF CLASS A, B, C, D, AND E AIRSPACE AREAS; AIR TRAFFIC SERVICE ROUTES; AND REPORTING POINTS

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

Authority: 49 U.S.C. 106(f), 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

- 2. The incorporation by reference in 14 CFR 71.1 of FAA Order JO 7400.11H, Airspace Designations and Reporting Points, dated August 11, 2023, and effective September 15, 2023, is amended as follows:

Paragraph 6005 Class E Airspace Areas Extending Upward From 700 Feet or More Above the Surface of the Earth.

* * * * *

ANE NH E5 Claremont, NH [Amended]

Claremont Municipal Airport, NH
(Lat. 43°22'14" N, long. 72°22'6" W)

That airspace extending upward from 700 feet above the surface within a 7.3-mile radius of the Claremont Municipal Airport and 2 miles each side of the 093° bearing from the airport, extending from the 7.3-mile radius to 15.1 miles east of the airport.

* * * * *

Issued in College Park, Georgia, on June 6, 2024.

Patrick Young,

Manager, Airspace & Procedures Team North, Eastern Service Center, Air Traffic Organization.

[FR Doc. 2024–12727 Filed 6–10–24; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF LABOR

Occupational Safety and Health Administration

29 CFR Part 1910

[Docket No. OSHA–2007–0073]

RIN 1218–AC91

Emergency Response Standard

AGENCY: Occupational Safety and Health Administration (OSHA), DOL.

ACTION: Notice of proposed rulemaking (NPRM); extension of comment period.

SUMMARY: OSHA is extending the period for submitting comments by 30 days to allow stakeholders interested in the NPRM on Emergency Response additional time to review the NPRM and collect information and data necessary for comment.

DATES: The comment period for the NPRM that was published at 89 FR 7774 on February 5, 2024, is extended. Comments on any aspect of the NPRM must be submitted by July 22, 2024.

ADDRESSES:

Written comments: You may submit comments and attachments, identified by Docket No. OSHA–2007–0073, electronically at www.regulations.gov, which is the Federal e-Rulemaking Portal. Follow the online instructions for making electronic submissions. The Federal e-Rulemaking Portal at www.regulations.gov is the only way to submit comments on this NPRM.

Instructions: All submissions must include the agency's name and the docket number for this rulemaking (Docket No. OSHA–2007–0073). All comments, including any personal information you provide, are placed in the public docket without change and may be made available online at www.regulations.gov. Therefore, OSHA cautions commenters about submitting information they do not want made available to the public or submitting materials that contain personal information (either about themselves or others), such as Social Security Numbers and birthdates.

Docket: To read or download comments or other material in the docket, go to Docket No. OSHA–2007–

0073 at www.regulations.gov. All comments and submissions are listed in the www.regulations.gov index; however, some information (e.g., copyrighted material) is not publicly available to read or download through that website. All comments and submissions, including copyrighted material, are available for inspection through the OSHA Docket Office. Documents submitted to the docket by OSHA or stakeholders are assigned document identification numbers (Document ID) for easy identification and retrieval. The full Document ID is the docket number plus a unique four-digit code. OSHA is identifying supporting information in this NPRM by author name and publication year, when appropriate. This information can be used to search for a supporting document in the docket at www.regulations.gov. Contact the OSHA Docket Office at 202-693-2350 (TTY number: 877-889-5627) for assistance in locating docket submissions.

FOR FURTHER INFORMATION CONTACT:

Press inquiries: Contact Frank Meilinger, Director, Office of Communications, U.S. Department of Labor; telephone: (202) 693-1999; email: meilinger.francis2@dol.gov.

General and technical information: Contact Mark Hagemann, Director, Office of Safety Systems, Directorate of Standards and Guidance, Occupational Safety and Health Administration, U.S. Department of Labor; telephone (202) 693-1950; email: osha.dsg@dol.gov.

SUPPLEMENTARY INFORMATION: On February 5, 2024, OSHA issued an NPRM to initiate rulemaking to update the existing Fire Brigades standard. The proposed rule would expand the scope of OSHA's standard to include a broad range of hazards emergency responders encounter during emergency response activities and would bring the standard in line with the Federal Emergency Management Agency's (FEMA) National Response Framework. It would also modernize the standard to align with the current industry consensus standards issued by the National Fire Protection Association (NFPA) on the safe conduct of emergency response activities.

The public comment period for the NPRM was to close on May 6, 2024, 90 days after publication of the NPRM. However, OSHA received requests from stakeholders to extend the comment period, and on March 28, 2024, published a notice announcing a 45-day extension of the comment period to June 21, 2024. OSHA has since received requests for an additional extension, (see, e.g., Document ID 1051, 1073,

1096, 1185). Stakeholders explained that they need additional time to carefully review the questions in the NPRM and gather data.

OSHA agrees to an additional extension of the public comment period and believes a 30-day extension is sufficient and appropriate in order to balance the agency's need for stakeholder input with the agency's desire to proceed with the rulemaking in a timely manner. Therefore, OSHA is extending the public comment period until July 22, 2024.

Additionally, several commenters submitted requests for a public hearing on the NPRM (see, e.g., Document ID 0435, 0444, 0456, 0459, 0463). OSHA plans to hold a virtual public hearing after the close of the comment period to allow stakeholders from all over the country to participate. OSHA will publish a separate notice at a future date to announce the details of the public hearing.

Authority and Signature

James S. Frederick, Deputy Assistant Secretary of Labor for Occupational Safety and Health, U.S. Department of Labor, 200 Constitution Avenue NW, Washington, DC 20210, authorized the preparation of this document pursuant to the following authorities: Sections 4, 6, and 8 of the Occupational Safety and Health Act of 1970 (29 U.S.C. 653, 655, 657); Secretary of Labor's Order 8-2020 (85 FR 58393 (Sept. 18, 2020)); 29 CFR part 1911; and 5 U.S.C. 553.

Signed at Washington, DC, on June 5, 2024.

James S. Frederick,

Deputy Assistant Secretary of Labor for Occupational Safety and Health.

[FR Doc. 2024-12731 Filed 6-10-24; 8:45 am]

BILLING CODE 4510-26-P

ENVIRONMENTAL PROTECTION AGENCY**40 CFR Part 52**

[EPA-R05-OAR-2024-0120; FRL-11915-02-R5]

Air Plan Approval; Michigan; Definitions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to approve a request submitted by the Michigan Department of Environment, Great Lakes, and Energy (EGLE) on February 28, 2024, to revise the Michigan state implementation plan (SIP). The revision

is updating the SIP for clarity by removing a redundant definition for "used oil."

DATES: Comments must be received on or before July 11, 2024.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA-R05-OAR-2024-0120 at <https://www.regulations.gov> or via email to langman.michael@epa.gov. For comments submitted at Regulations.gov, follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from the docket. EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI), Proprietary Business Information (PBI), 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. 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, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section. For the full EPA public comment policy, information about CBI, PBI, or multimedia submissions, and general guidance on making effective comments, please visit <https://www.epa.gov/dockets/commenting-epa-dockets>.

FOR FURTHER INFORMATION CONTACT:

Charles Hatten, Air and Radiation Division (AR18J), Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886-6031, hatten.charles@epa.gov. The EPA Region 5 office is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays.

SUPPLEMENTARY INFORMATION: In the Final Rules section of this **Federal Register**, EPA is approving the state's SIP submittal as a direct final rule without prior proposal because the Agency views this as a noncontroversial submittal and anticipates no adverse comments. A detailed rationale for the approval is set forth in the direct final rule. If no adverse comments are received in response to this rule, no further activity is contemplated. If EPA receives adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule

based on this proposed rule. EPA will not institute a second comment period. Any parties interested in commenting on this action should do so at this time. Please note that if EPA receives adverse comment on an amendment, paragraph, or section of this rule and if that provision may be severed from the remainder of the rule, EPA may adopt as final those provisions of the rule that are not the subject of an adverse comment. For additional information, see the direct final rule which is located in the Rules section of this **Federal Register**.

Dated: June 3, 2024.

Debra Shore,

Regional Administrator, Region 5.

[FR Doc. 2024–12520 Filed 6–10–24; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 721

[EPA–HQ–OPPT–2022–0771; FRL–11912–01–OCSPF]

RIN 2070–AB27

Significant New Use Rules on Certain Chemical Substances (22–4.5e)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing significant new use rules (SNURs) under the Toxic Substances Control Act (TSCA) for chemical substances that were the subject of premanufacture notices (PMNs) and are also subject to a TSCA Order. The SNURs require persons who intend to manufacture (defined by statute to include import) or process any of these chemical substances for an activity that is proposed as a significant new use by this rule to notify EPA at least 90 days before commencing that activity. The required notification initiates EPA's evaluation of the conditions of use for that chemical substance. In addition, the manufacture or processing for the significant new use may not commence until EPA has conducted a review of the required notification, made an appropriate determination regarding that notification, and taken such actions as required by that determination.

DATES: Comments must be received on or before July 11, 2024.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPPT–2022–0771, at <https://www.regulations.gov>. Follow the online instructions for submitting

comments. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Additional instructions on commenting and visiting the docket, along with more information about dockets generally, is available at <https://www.epa.gov/dockets>.

FOR FURTHER INFORMATION CONTACT:

For technical information contact: William Wyson, New Chemicals Division (7405M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460–0001; telephone number: (202) 564–4163; email address: wysong.william@epa.gov.

For general information contact: The TSCA–Hotline, ABVI–Goodwill, 422 South Clinton Ave., Rochester, NY 14620; telephone number: (202) 554–1404; email address: TSCA-Hotline@epa.gov.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. What is the Agency's authority for taking this action?

TSCA section 5(a)(2) (15 U.S.C. 2604(a)(2)) authorizes EPA to determine that a use of a chemical substance is a “significant new use.” EPA must make this determination by rule after considering all relevant factors, including the factors in TSCA section 5(a)(2) (see also the discussion in Unit II.).

B. What action is the Agency taking?

EPA is proposing SNURs for the chemical substances discussed in Unit III. These SNURs, if finalized as proposed, would require persons who intend to manufacture or process any of these chemical substances for an activity that is designated as a significant new use to notify EPA at least 90 days before commencing that activity.

C. Does this action apply to me?

1. General Applicability

This action applies to you if you manufacture, process, or use the chemical substances identified in Unit III. This may include entities in North American Industrial Classification System (NAICS) codes 325 and 324110, e.g., chemical manufacturing and petroleum refineries.

2. Applicability to Importers and Exporters

This action may also apply to certain entities through pre-existing import certification and export notification

requirements under TSCA (<https://www.epa.gov/tsc-import-export-requirements>).

Chemical importers are subject to TSCA section 13 (15 U.S.C. 2612), the requirements promulgated at 19 CFR 12.118 through 12.127 (see also 19 CFR 127.28), and the EPA policy in support of import certification at 40 CFR part 707, subpart B. Chemical importers must certify that the shipment of the chemical substance complies with all applicable rules and orders under TSCA, including regulations issued under TSCA sections 5, 6, 7 and Title IV.

Pursuant to 40 CFR 721.20, any persons who export or intend to export a chemical substance that is the subject of this proposed rule on or after July 11, 2024 are subject to TSCA section 12(b) (15 U.S.C. 2611(b)) and must comply with the export notification requirements in 40 CFR part 707, subpart D.

D. What are the incremental economic impacts of this action?

EPA has evaluated the potential costs of establishing SNUN reporting requirements for potential manufacturers (including importers) and processors of the chemical substances subject to these proposed SNURs. This analysis, which is available in the docket, is briefly summarized here.

1. Estimated Costs for SNUN Submissions

If a SNUN is submitted, costs are an estimated \$45,000 per SNUN submission for large business submitters and \$14,500 for small business submitters. These estimates include the cost to prepare and submit the SNUN (including registration for EPA's Central Data Exchange (CDX)), and the payment of a user fee. Businesses that submit a SNUN would be subject to either a \$37,000 user fee required by 40 CFR 700.45(c)(2)(ii) and (d), or, if they are a small business as defined at 13 CFR 121.201, a reduced user fee of \$6,480 (40 CFR 700.45(c)(1)(ii) and (d)) per fiscal year 2022. The costs of submission for SNUNs will not be incurred by any company unless a company decides to pursue a significant new use as defined in these SNURs. Additionally, these estimates reflect the costs and fees as they are known at the time of this rulemaking.

2. Estimated Costs for Export Notifications

EPA has also evaluated the potential costs associated with the export notification requirements under TSCA

section 12(b) and the implementing regulations at 40 CFR part 707, subpart D. For persons exporting a substance that is the subject of a SNUR, a one-time notice to EPA must be provided for the first export or intended export to a particular country. The total costs of export notification will vary by chemical, depending on the number of required notifications (*i.e.*, the number of countries to which the chemical is exported). While EPA is unable to make any estimate of the likely number of export notifications for the chemical substances covered by these SNURs, as stated in the accompanying economic analysis, the estimated cost of the export notification requirement on a per unit basis is approximately \$106.

E. What should I consider as I prepare my comments for EPA?

1. Submitting CBI

Do not submit CBI to EPA through email or <https://www.regulations.gov>. If you wish to include CBI in your comment, please follow the applicable instructions at <https://www.epa.gov/dockets/commenting-epa-dockets#rules> and clearly mark the information that you claim to be CBI. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR parts 2 and 703.

2. Tips for Preparing Your Comments

When preparing and submitting your comments, see the commenting tips at <https://www.epa.gov/dockets/commenting-epa-dockets>.

II. Background

This unit provides general information about SNURs. For additional information about EPA's new chemical program go to <https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca>.

A. Significant New Use Determination Factors

TSCA section 5(a)(2) states that EPA's determination that a use of a chemical substance is a significant new use must be made after consideration of all relevant factors, including:

- The projected volume of manufacturing and processing of a chemical substance.
- The extent to which a use changes the type or form of exposure of human beings or the environment to a chemical substance.
- The extent to which a use increases the magnitude and duration of exposure of human beings or the environment to a chemical substance.
- The reasonably anticipated manner and methods of manufacturing,

processing, distribution in commerce, and disposal of a chemical substance.

In determining what would constitute a significant new use for the chemical substances that are the subject of these SNURs, EPA considered relevant information about the toxicity of the chemical substances, and potential human exposures and environmental releases that may be associated with the substances, in the context of the four bulleted TSCA section 5(a)(2) factors listed in this unit and discussed in Unit III.

These proposed SNURs include PMN substances that are subject to Orders issued under TSCA section 5(e)(1)(A), as required by the determinations made under TSCA section 5(a)(3)(B). The TSCA Orders require protective measures to limit exposures or otherwise mitigate the potential unreasonable risk. The proposed SNURs identify as significant new uses any manufacturing, processing, use, distribution in commerce, or disposal that does not conform to the restrictions imposed by the underlying TSCA Orders, consistent with TSCA section 5(f)(4).

B. Rationale and Objectives of the SNURs

1. Rationale

Under TSCA, no person may manufacture a new chemical substance or manufacture or process a chemical substance for a significant new use until EPA makes a determination as described in TSCA section 5(a) and takes any required action. The issuance of a SNUR is not a risk determination itself, only a notification requirement for "significant new uses," so that the Agency has the opportunity to review the SNUN for the significant new use and make a TSCA section 5(a)(3) risk determination.

During review of the PMNs submitted for these chemical substances, EPA concluded that regulation was warranted under TSCA section 5(e), pending the development of information sufficient to make reasoned evaluations of the health or environmental effects of these chemical substances. The basis for such findings is outlined in Unit IV. Based on these findings, TSCA Orders requiring the use of appropriate exposure controls were negotiated with the PMN submitters. As a general matter, EPA believes it is necessary to follow the TSCA Orders with a SNUR that identifies the absence of those protective measures as significant new uses to ensure that all manufacturers and processors—not just the original submitter—are held to the same standard.

2. Objectives

EPA is proposing these SNURs because the Agency wants:

- To identify as significant new uses any manufacturing, processing, use, distribution in commerce, or disposal that does not conform to the restrictions imposed by the underlying TSCA Orders, consistent with TSCA section 5(f)(4).

- To have an opportunity to review and evaluate data submitted in a SNUN before the submitter begins manufacturing or processing a listed chemical substance for the described significant new use.

- To be obligated to make a determination under TSCA section 5(a)(3) regarding the use described in the SNUN, under the conditions of use. The Agency will either determine under TSCA section 5(a)(3)(C) that the significant new use is not likely to present an unreasonable risk, including an unreasonable risk to a potentially exposed or susceptible subpopulation identified as relevant by the Administrator under the conditions of use, or make a determination under TSCA section 5(a)(3)(A) or (B) and take the required regulatory action associated with the determination, before manufacture or processing for the significant new use of the chemical substance can occur.

Issuance of a proposed SNUR for a chemical substance does not signify that the chemical substance is listed on the TSCA Chemical Substance Inventory (TSCA Inventory). Guidance on how to determine if a chemical substance is on the TSCA Inventory is available at <https://www.epa.gov/tsca-inventory>.

C. Significant New Uses Claimed as CBI

EPA is proposing to establish certain significant new uses which have been claimed as CBI subject to Agency confidentiality regulations at 40 CFR part 2 and 40 CFR part 720, subpart E. Absent a final determination or other disposition of the confidentiality claim under 40 CFR part 2 procedures, EPA is required to keep this information confidential. EPA promulgated a procedure at 40 CFR 721.11 to deal with the situation where a specific significant new use is CBI.

Under these procedures a manufacturer or processor may request EPA to determine whether a specific use would be a significant new use under the rule. The manufacturer or processor must show that it has a *bona fide* intent to manufacture or process the chemical substance and must identify the specific use for which it intends to manufacture or process the chemical substance. If

EPA concludes that the person has shown a *bona fide* intent to manufacture or process the chemical substance, EPA will tell the person whether the use identified in the *bona fide* submission would be a significant new use under the rule. Since most of the chemical identities of the chemical substances subject to these SNURs are also CBI, manufacturers and processors can combine the *bona fide* submission under the procedure in 40 CFR 721.11 into a single step.

If EPA determines that the use identified in the *bona fide* submission would not be a significant new use, *i.e.*, the use does not meet the criteria specified in the rule for a significant new use, that person can manufacture or process the chemical substance so long as the significant new use trigger is not met. In the case of a production volume trigger, this means that the aggregate annual production volume does not exceed that identified in the *bona fide* submission to EPA. Because of confidentiality concerns, EPA does not typically disclose the actual production volume that constitutes the use trigger. Thus, if the person later intends to exceed that volume, a new *bona fide* submission would be necessary to determine whether that higher volume would be a significant new use.

D. Applicability of General Provisions

General provisions for SNURs appear in 40 CFR part 721, subpart A. These provisions describe persons subject to SNURs, recordkeeping requirements, exemptions to reporting requirements, and applicability of the rule to uses occurring before the effective date of the rule.

Pursuant to 40 CFR 721.1(c), persons subject to SNURs must comply with the same requirements and EPA regulatory procedures as submitters of PMNs under TSCA section 5(a)(1)(A). In particular, these requirements include the information submission requirements of TSCA sections 5(b) and 5(d)(1), the exemptions authorized by TSCA sections 5(h)(1), 5(h)(2), 5(h)(3), and 5(h)(5) and the regulations at 40 CFR part 720. In addition, provisions relating to user fees appear at 40 CFR part 700.

Once EPA receives a SNUN, EPA must either determine that the significant new use is not likely to present an unreasonable risk of injury under the conditions of use for the chemical substance or take such regulatory action as is associated with an alternative determination under TSCA section 5 before the manufacture (including import) or processing for the significant new use can commence. If EPA determines that the conditions of

use of the chemical substance is not likely to present an unreasonable risk, EPA is required under TSCA section 5(g) to publish a statement of EPA's findings in the **Federal Register**.

As discussed in Unit I.C.2., persons who export or intend to export a chemical substance identified in a proposed or final SNUR are subject to the export notification provisions of TSCA section 12(b), and persons who import a chemical substance identified in a final SNUR are subject to the TSCA section 13 import certification requirements. See also <https://www.epa.gov/tsca-import-export-requirements>.

E. Applicability of the Proposed SNURs to Uses Occurring Before the Effective Date of the Final Rule

To establish a significant new use, EPA must determine that the use is not ongoing. The chemical substances subject to this proposed rule have undergone premanufacture review and received determinations under TSCA section 5(a)(3)(C). TSCA Orders have been issued for these chemical substances and the PMN submitters are required by the TSCA Orders to submit a SNUN before undertaking activities that would be designated as significant new uses in these SNURs. Additionally, the identities of many of the chemical substances subject to this proposed rule have been claimed as confidential per 40 CFR 720.85, further reducing the likelihood that another party would manufacture or process the substances for an activity that would be designated as a significant new use. Based on this, the Agency believes that it is highly unlikely that any of the significant new uses identified in Unit III. are ongoing.

When the chemical substances identified in Unit III. are added to the TSCA Inventory, EPA recognizes that, before the rule is effective, other persons might engage in a use that has been identified as a significant new use. Persons who begin manufacture or processing of the chemical substances for a significant new use identified on or after the designated cutoff date specified in Unit III.A. would have to cease any such activity upon the effective date of the final rule. To resume their activities, these persons would have to first comply with all applicable SNUR notification requirements and EPA would have to take action under TSCA section 5 allowing manufacture or processing to proceed.

F. Important Information About SNUN Submissions

1. SNUN Submissions

SNUNs must be submitted on EPA Form No. 7710–25, generated using e-PMN software, and submitted to the Agency in accordance with the procedures set forth in 40 CFR 720.40 and 721.25. E-PMN software is available at <https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca>.

2. Development and Submission of Information

EPA recognizes that TSCA section 5 does not require development of any particular new information (*e.g.*, generating test data) before submission of a SNUN. There is an exception: If a person is required to submit information for a chemical substance pursuant to a rule, order or consent agreement under TSCA section 4, then TSCA section 5(b)(1)(A) requires such information to be submitted to EPA at the time of submission of the SNUN.

In the absence of a rule, TSCA Order, or consent agreement under TSCA section 4 covering the chemical substance, persons are required only to submit information in their possession or control and to describe any other information known to or reasonably ascertainable by them (see 40 CFR 720.50). However, upon review of PMNs and SNUNs, the Agency has the authority to require appropriate testing. To assist with EPA's analysis of the SNUN, submitters are encouraged, but not required, to provide the potentially useful information identified for the chemical substance in Unit III.C.

EPA strongly encourages persons, before performing any testing, to consult with the Agency pertaining to protocol selection. Furthermore, pursuant to TSCA section 4(h), which pertains to reduction of testing in vertebrate animals, EPA encourages consultation with the Agency on the use of alternative test methods and strategies (also called New Approach Methodologies, or NAMs), if available, to generate the recommended test data. EPA encourages dialog with Agency representatives to help determine how best the submitter can meet both the data needs and the objective of TSCA section 4(h). For more information on alternative test methods and strategies to reduce vertebrate animal testing, visit <https://www.epa.gov/assessing-and-managing-chemicals-under-tsca/alternative-test-methods-and-strategies-reduce>.

The potentially useful information described in Unit III.C. for these

chemical substances may not be the only means of providing information to evaluate the chemical substance associated with the significant new uses. However, submitting a SNUN without any information may increase the likelihood that EPA will take action under TSCA sections 5(e) or 5(f). EPA recommends that potential SNUN submitters contact EPA early enough so that they will be able to conduct the appropriate tests to provide useful information with their SNUN submission.

SNUN submitters should be aware that EPA will be better able to evaluate SNUNs which provide detailed information on the following:

- Human exposure and environmental release that may result from the significant new use of the chemical substances.

III. Chemical Substances Subject to These Proposed SNURs

A. What is the designated cutoff date for ongoing uses?

EPA designates June 11, 2024, as the cutoff date for determining whether the new use is ongoing. This designation is explained in more detail in Unit II.E.

B. What information is provided for each chemical substance?

For each chemical substance identified in Unit III.C., EPA provides the following information:

- PMN number (the proposed CFR citation assigned in the regulatory text section of this document).
- Chemical name (generic name, if the specific name is claimed as CBI).
- Chemical Abstracts Service Registry Number (CASRN) (if assigned for non-confidential chemical identities).
- Basis for the action or, as applicable, the effective date of and basis for the TSCA Order.
- Potentially useful information.

The regulatory text section of the proposed rule specifies the activities designated as significant new uses. Certain new uses, including production volume limits and other uses designated in the proposed rules, may be claimed as CBI.

These proposed rules include PMN substances that are subject to orders issued under TSCA section 5(e)(1)(A), as required by the determinations made under TSCA section 5(a)(3)(B). Those TSCA Orders require protective measures to limit exposures or otherwise mitigate the potential unreasonable risk. The proposed SNURs identify as significant new uses any manufacturing, processing, use, distribution in commerce, or disposal

that does not conform to the restrictions imposed by the underlying TSCA Orders, consistent with TSCA section 5(f)(4).

Where EPA determined that the PMN substance may present an unreasonable risk of injury to human health via inhalation exposure, the underlying TSCA Order usually requires that potentially exposed employees wear specified respirators unless actual measurements of the workplace air show that air-borne concentrations of the PMN substance are below a New Chemical Exposure Limit (NCEL). The Comprehensive NCELS provisions in TSCA Orders include requirements addressing performance criteria for sampling and analytical methods, periodic monitoring, respiratory protection, and recordkeeping. No comparable NCEL provisions for SNURs currently exist in 40 CFR part 721, subpart B. Therefore, for these cases, the individual SNURs in 40 CFR part 721, subpart E, will state that persons subject to the SNUR who wish to pursue NCELS as an alternative to the 40 CFR 721.63 respirator requirements may request to do so under 40 CFR 721.30. EPA expects that persons whose 40 CFR 721.30 requests to use the NCELS approach for SNURs are approved by EPA, will be required to comply with NCELS provisions that are comparable to those contained in the corresponding TSCA Order.

C. Which chemical substances are subject to this proposed rule?

The substances subject to the proposed rules in this document are as follows:

PMN Number: P-18-398 (40 CFR 721.11860)

Chemical Name: 1,2-Ethanediamine, N-(1-methylethyl)-N-[2-[(1-methylethyl)amino]ethyl]-.

CASRN: 10507-06-9.

Effective Date of TSCA Order: April 13, 2022.

Basis for TSCA Order: The PMN states that the use will be as an intermediate. Based on comparison to analogous substances, EPA has identified concerns for acute toxicity, skin sensitization, eyes, skin, and respiratory tract corrosion, and systemic, reproductive, and developmental effects. Based on comparison to analogous aliphatic amines, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 210 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may

present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified full facepiece gas/vapor respirator with an APF of at least 50 where there is a potential for inhalation exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS; and
- No use of the PMN substance other than for the confidential use allowed in the Order.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity and skin sensitization testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P-19-49 (40 CFR 721.11861)

Chemical Name: Fatty acids, polymers with substituted carbomonocycles, dialkanolamine, alkyl substituted alkanediamine and halo-substituted heteromonocycle, formates (salts) (generic).

CASRN: Not available.

Effective Date of Modified TSCA Order: May 19, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as an isolated intermediate coating resin. Based on the amine content and the surfactant properties of the PMN substance, EPA has identified concerns for irritation to all tissues. Based on formic acid, EPA has also identified concerns for neurotoxicity, blood toxicity, and developmental toxicity. Based on test data on the PMN substance, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 114 ppb. EPA issued an Order under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information

to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. The Order, effective October 27, 2020, required the submitter of P-19-49 to submit to EPA the results of certain toxicity testing before any manufacturing (which includes import), processing, or use of the PMN substance. On September 17, 2021, the PMN submitter provided the results of three environmental toxicity studies in accordance with the requirements of the Order. EPA reviewed those studies and determined the studies to be valid. EPA subsequently modified the terms of the Order to mitigate any unreasonable risks to human health and the environment and issued a modified Order, effective May 19, 2022. To protect against these potential risks, the modified Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;
- No manufacture or processing of the PMN substance in a manner that generates a vapor, mist, or aerosol;
- No use of the PMN substance in a manner that generates a vapor, mist, or aerosol that results in inhalation to industrial or commercial workers;
- No manufacture the PMN substance to contain the confidential residual identified in the Order at greater than 0.1%; and
- No release of the PMN substance resulting in surface water concentrations that exceed 114 ppb.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of skin irritation, eye irritation, developmental/reproductive toxicity, pulmonary effects, and neurotoxicity testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P-19-160 (40 CFR 721.11862)

Chemical Name: Alkanesulfonic acid, 2-[(2-aminoethyl)heteroatom-substituted]-, sodium salt (1:1), polymer with .alpha.-[2,2-bis(hydroxymethyl)butyl]-.omega.-methoxypoly(oxy-1,2-ethanediyl) and 1,1'-methylenebis[4-isocyanatocyclohexane], acrylic acid-dipentaerythritol reaction products-and polypropylene glycol ether with pentaerythritol (4:1) triacrylate-blocked (generic).

CASRN: Not available.

Effective Date of TSCA Order: July 27, 2022.

Basis for TSCA Order: The PMN states that the use will be as a component of a UV curable printing ink. Based on analogue data and information provided in the SDS, EPA has identified concerns for skin irritation and dermal and respiratory sensitization. Based on analogue data and data on a component of the PMN substance, EPA has identified concerns for eye irritation/corrosion and genotoxicity. Based on analogue data, EPA has also identified concerns for systemic toxicity, developmental toxicity, and neurotoxicity. Based on comparison to analogous polyanionic polymers, EPA predicts that the PMN substance has low environmental hazard. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;
- No use of the PMN substance in a consumer product;
- No manufacture, processing, or use of the PMN substance in any manner that results in inhalation exposure; and
- No release of the PMN substance resulting in surface water concentrations that exceed 302 ppb.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a

SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of specific target organ toxicity, pulmonary effects, reproductive toxicity (developmental effects), skin sensitization, skin irritation, eye damage, carcinogenicity, and genetic toxicity testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P-20-101 (40 CFR 721.11863)

Chemical Name: Alkanoic acid, hydroxy-(hydroxyalkyl)-alkyl-, polymer with .alpha.-[(hydroxyalkyl)alkyl]-.omega.-alkoxypoly(oxy-alkanediyl), (haloalkyl)oxiane polymer (alkylalkylidene)bis[hydroxycarbomonocycle] alkenoate and isocyanate-alkyl-carbomonocycle, hydroxyalkyl acrylate-blocked (generic).

CASRN: Not available.

Effective Date of TSCA Order: July 27, 2022.

Basis for TSCA Order: The PMN states that the use will be as a coating resin. Based on structural alerts and test data for an analogue and feedstock component, EPA has identified concerns for skin, eye, and respiratory tract irritation; skin and respiratory sensitization; acute neurotoxicity; and systemic and reproductive effects. Based on test data for a metabolite of the PMN substance, as well as analogues of the LMW fraction, EPA has identified concerns for eye and respiratory tract irritation; skin sensitization; portal-of-entry effects; and systemic, reproductive, and developmental effects. Based on hazard data for an analogous chemical and comparison to analogous polyanionic polymers (and monomers), EPA predicts that the substance has moderate environmental toxicity. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified combination particulate and gas/vapor respirator with an APF of at least 50 where there is a potential for inhalation exposure;

- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;

- No manufacture or processing of the PMN substance with greater than 20% (by weight) oligomer content below 1,000 daltons (*i.e.*, low molecular weight species);

- No processing or use of the PMN substance for manual spray application;

- No processing of the PMN substance for use in a consumer product; and

- No use of the PMN substance in a consumer product.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of specific target organ toxicity testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require this test, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P–20–182 (40 CFR 721.11864)

Chemical Name: 1,4-Benzenedicarboxylic acid, bis[2-(2-butoxyethoxy)ethyl] ester (9CI).

CASRN: 90430–63–0.

Effective Date of TSCA Order: April 21, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a plasticizer for PVC formulations. Based on the structural alert for ethylene glycol ethers, EPA has identified concerns for neurotoxicity, kidney effects, immunotoxicity, and blood effects. Based on test data on the PMN substance, EPA has identified concerns for skin sensitization and mutagenicity. Based on test data for an analogue, EPA has identified concerns for skin sensitization. Based on test data on potential metabolites, EPA has also identified concerns for acute toxicity (mortality), lung toxicity, systemic effects, and developmental effects. Based on test data on the PMN substance and comparison to analogous chemical substances, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 4 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I),

based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;

- Use of a NIOSH-certified particulate respirator with an APF of at least 1,000 where there is a potential for inhalation exposure, or compliance with an NCEL of 0.01 mg/m³ as an 8-hour time-weighted average to prevent inhalation exposure;

- No release of the PMN substance resulting in surface water

- concentrations that exceed 4 ppb; and

- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of metabolism or pharmacokinetics, skin sensitization, reproductive toxicity, developmental toxicity, immunotoxicity, neurotoxicity, specific target organ toxicity, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P–21–56 (40 CFR 721.11865)

Chemical Name: Isocyanic acid, polyalkylenepolyarylene ester, polymer with alkyl-hydroxyalkyl-alkanediol, alkoxyalcohol and alkoxyalkoxyalcohol-blocked (generic).

CASRN: Not available.

Effective Date of TSCA Order: May 11, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a component of coatings. Based on data on an analogous chemical substance, EPA has identified concerns for acute neurotoxicity and skin sensitization. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and

5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;

- Use of a NIOSH-certified particulate, gas/vapor, or combination particulate and gas/vapor (as appropriate to the conditions) respirator with an APF of at least 50, or 1,000 if spray applied, where there is a potential for inhalation exposure;

- No manufacture of the PMN substance beyond 24 months without submittal to EPA of the results of certain testing described in the Testing section of the Order;

- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS; and

- No use of the PMN substance in a consumer product.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of neurotoxicity and acute toxicity testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information. In addition, the submitter has agreed not to exceed the time limit specified in the Order without performing the required testing outlined in the Testing section of the Order.

PMN Numbers: P–21–58 (40 CFR 721.11866), P–21–60 (40 CFR 721.11867), and P–21–61 (40 CFR 721.11868)

Chemical Names: Substituted alkanolic acid, compound with aminoalkylalkyl-aminoalkylalkoxy-polyoxyalkylalkanediyl, polymer with haloalkyl-epoxide and alkylalkylidene-cycloarylalcohol (generic) (P–21–58); Bisphenol A epichlorohydrin polymer with alkylpolyalkene-polyarylene-hydroxypolyoxyalkyldiyl reaction products with alkylalkylidenealkylalkylidene-

aminoalkyl-alkanepolyamine and alkylaminoalkanol (generic) (P-21-60); and Sulfur based acid, compds. with modified bisphenol A-epichlorohydrin-polyalkylene polyol ether with bisphenol A polymer-N-dialkylalkylidene-N-(dialkylalkylidene)aminoalkyl-alkanepolyamine-alkylaminoalkanol reaction products (generic) (P-21-61).

*CASRN*s: Not available.

Effective Date of TSCA Order: May 9, 2022.

Basis for TSCA Order: The PMNs state that the generic (non-confidential) use will be as a component in coatings (P-21-58 and P-21-61) and as an isolated intermediate (P-21-60). Based on the surfactant-like properties of P-21-58, EPA has identified concerns for lung effects and irritation to the skin, eyes, and respiratory tract. Based on data for an analogue of the lower molecular weight fraction of P-21-58, EPA has also identified concerns for neurotoxicity, cardiovascular effects, and systemic effects. Based on a structural alert for aliphatic amines and data for the expected hydrolysis product, EPA has identified concerns for irritation to the skin, eyes, and respiratory tract; neurotoxicity; mortality; systemic effects; developmental effects; and carcinogenicity for P-21-60 and P-21-61. Based on comparison to analogous polycationic polymers, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 50 ppb for P-21-58. Based on comparison to analogous aliphatic amines and polycationic polymers, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 11 ppb for P-21-60. Based on comparison to analogous aliphatic amines, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 11 ppb for P-21-61. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substances may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;
- No manufacture, processing, or use of the PMN substances in any manner that results in inhalation exposure;

- No use of the PMN substances in a consumer product;
- No release of P-21-58 resulting in surface water concentrations that exceed 50 ppb;
- No release of P-21-60, or any waste stream containing P-21-60, into water; and
- No release of P-21-61 resulting in surface water concentrations that exceed 11 ppb.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of specific target organ toxicity, neurotoxicity, skin irritation, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substances. EPA has also determined that the results of eye irritation, pulmonary effects, developmental toxicity, and carcinogenicity testing may be potentially useful to characterize the health effects of P-21-60 and P-21-61. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P-21-66 (40 CFR 721.11869)

Chemical Name: 1,2-Alkanediol, 3-aryloxy, mono phosphate ester (generic).
CASRN: Not available.

Effective Date of TSCA Order: June 10, 2022.

Basis for TSCA Order: The PMN states that the use will be as a blended or standalone epoxy curative (hardener) and foaming agent when blended with certain ingredients. Based on information provided in the SDS and the low pH of the PMN substance when neat, EPA has identified concerns for skin, eye, and respiratory tract corrosion. Based on release of the free phosphate, EPA has also identified concerns for blood effects and irritation to the skin, eyes, and respiratory tract. Based on analogue data and the structural alert for phosphate esters, EPA has identified concerns for acute toxicity, acute neurotoxicity, corrosion to skin and eyes, and delayed neurotoxicity. Based on test data for an analogue of the hydrolysis product, EPA has also identified concerns for acute

toxicity, eye irritation, systemic effects, and developmental effects. Based on comparison to an analogous chemical substance, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 3 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;
- No use of the PMN substance in a consumer product;
- No use of the PMN substance other than as an epoxy curative;
- No manufacture, processing, or use of the PMN substance in any manner that results in inhalation exposure or that results in fugitive air emissions; and
- No release of the PMN substance, or any waste stream containing the PMN substance, into water.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of acute toxicity, eye irritation/corrosion, skin corrosion, specific target organ toxicity, pulmonary effects, developmental toxicity, neurotoxicity, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P-21-68 (40 CFR 721.11870)

Chemical Name: Metalloxanes, alkyl, alkyl group-terminated, reaction products with dihalo-dialkylalkylaryl-alkyl-polycyclic-ylidene(dialkylsilylene)-dialkylalkylaryl-alkylalkyl-polycyclic-

ylidene, metal oxide and nonmetallic oxide (generic).

CASRN: Not available.

Effective Date of TSCA Order: June 27, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a polymerization catalyst. Based on the reactivity of the PMN substance and the release of hydrochloric acid, EPA has identified concerns for an acute handling hazard; irritation and corrosion to the skin, eyes, and respiratory tract; and lung overload (if respirable, poorly soluble particulates are inhaled). Based on analogue data, EPA has identified concerns for irritation to skin, eyes, and respiratory tract; lung effects; serious eye damage and ocular corrosion; portal-of-entry effects; mutagenicity; acute neurotoxicity; systemic effects; reproductive/developmental effects; and dermal and respiratory sensitization. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;
- No manufacture, processing, or use of the PMN substance other than in an enclosed process;
- No manufacture, processing, or use of the PMN substance in any manner that results in inhalation or dermal exposure to the PMN substance; and
- No release of the PMN substance resulting in surface water concentrations that exceed 50 ppb.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of acute toxicity, skin sensitization, skin corrosion, specific target organ toxicity, pulmonary effects, reproductive toxicity, and mutagenicity testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require

these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P-21-83 (40 CFR 721.11871)

Chemical Name: Alkenoic acid, reaction products with pentaerythritol, polymers with diisocyanatoalkane and heteromonocycle homopolymer esters with alkenoic acid-pentaerythritol reaction products (generic).

CASRN: Not available.

Effective Date of TSCA Order: June 6, 2022.

Basis for TSCA Order: The PMN states that the use will be as a UV curable resin. Based on information provided in the SDS and a structural alert for acrylates, EPA has identified concerns for irritation to the skin, eyes, and respiratory tract. Based on a structural alert for acrylates for the low molecular weight fraction, OECD QSAR Toolbox results for the feedstock present as a residual, and information provided in the SDS, EPA has also identified concerns for skin and respiratory sensitization. Based on multifunctional reactive groups, EPA has identified respiratory sensitization. Based on test data for the feedstock residual, EPA has identified concerns for skin irritation, clinical signs, systemic effects, and irritation in the GI tract. Based on comparison to analogous acrylates/methacrylates and esters, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 1 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified Combination Particulate and Gas/Vapor respirator with an APF of 1,000 where there is a potential for inhalation exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;
- No use of the PMN substance in a consumer product; and
- No release of the PMN substance resulting in surface water concentrations that exceed 1 ppb.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of skin irritation, eye damage, specific target organ toxicity, and skin sensitization testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P-21-84 (40 CFR 721.11872)

Chemical Name: Carbopolycycle octa-alkene, halo (generic).

CASRN: Not available.

Effective Date of TSCA Order: May 27, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a chemical intermediate. Based on test data for an analogue, EPA has identified concerns for severe irritation/corrosion to the skin, eyes, and respiratory tract, acute toxicity, and mutagenicity. Based on OECD Toolbox results, EPA has also identified concerns for skin sensitization. Based on comparison to analogous benzyl halides, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 7 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified Gas/Vapor respirator with an APF of at least 50 where there is a potential for inhalation exposure;
- No release of the PMN substance resulting in surface water concentrations that exceed 7 ppb; and
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of acute toxicity, specific target organ toxicity, skin corrosion, eye damage, skin sensitization, genetic toxicity, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P–21–92 (40 CFR 721.11873)

Chemical Name: 2-Propenoic acid, (polyhydro-1,3-dioxo-2H-isoindol-2-yl)alkyl ester (generic).

CASRN: Not available.

Effective Date of TSCA Order: April 5, 2022.

Basis for TSCA Order: The PMN states that the uses of the PMN substance will be for thermoset composites, 3D printing, and industrial coatings. Based on test data for the PMN substance, EPA has identified concerns for skin irritation. Based on information provided in the SDS, EPA has also identified concerns for skin irritation and eye irritation. Based on test data for a hydrolysis product, EPA has identified concerns for developmental, body weight, and portal-of-entry (inhalation and oral) effects. Based on test data for an analogue, EPA has also identified concerns for clinical signs, skin irritation, eye irritation, and developmental, body weight, and lung effects. Based on test data for an analogue, EPA identified concerns for portal-of-entry (inhalation) and liver effects. Based on comparison to analogous acrylates/methacrylates and imides, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 13 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to

human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified combination particulate and gas/vapor respirator with an APF of at least 10 to prevent inhalation exposure where there is a potential for inhalation exposure;
- Disposal of the PMN substance only by incineration or by RCRA Subtitle C landfill;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;
- No use of the PMN substance in a consumer product;
- No use of the PMN substance where the concentration of the PMN substance exceeds 40% in formulation when inhalation exposure is expected; and
- No release of the PMN substance, or any waste stream containing the PMN substance, into water.

The proposed SNUR designates as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that would be designated by this SNUR. EPA has determined that the results of developmental toxicity, specific target organ toxicity, pulmonary effects, and aquatic toxicity testing may be potentially useful to characterize the environmental and human health effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P–21–102 (40 CFR 721.11874)

Chemical Name: Heteromonocycle, polymer, [2-[(1-oxo-2-propen-1-yl)oxy]alkyl]ester (generic).

CASRN: Not available.

Effective Date of TSCA Order: May 20, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a raw material for industrial additive manufacturing, UV-curable inks, coatings and adhesives. Based on

TSCA New Chemical Category document for acrylates, EPA has identified concerns for skin sensitization and irritation to the skin, eyes, and respiratory tract. Based on test data for an analogue of the low molecular weight fraction, EPA has also identified concerns for systemic and developmental effects. Based on comparison to analogous acrylates/methacrylates and esters, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 337 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified Combination Particulate and Gas/Vapor respirator with an APF of at least 10 where there is a potential for inhalation exposure;
- No use of the PMN substance in a consumer product;
- No release of the PMN substance resulting in surface water concentrations that exceed 337 ppb; and
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of skin irritation, skin sensitization, eye damage, developmental toxicity, specific target organ toxicity, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Numbers: P-21-109 (40 CFR 721.11875), P-21-110 (40 CFR 721.11876), P-21-111 (40 CFR 721.11877), P-21-112 (40 CFR 721.11878), P-21-113 (40 CFR 721.11879), P-21-114 (40 CFR 721.11880), P-21-116 (40 CFR 721.11881), P-21-117 (40 CFR 721.11882), P-21-118 (40 CFR 721.11883), P-21-119 (40 CFR 721.11884), P-21-121 (40 CFR 721.11885), P-21-122 (40 CFR 721.11886), and P-21-123 (40 CFR 721.11887)

Chemical Names: Hydrocarbons linear and branched, light alkylate (generic) (P-21-109), Hydrocarbons linear and branched, light catalytic cracked (generic) (P-21-110), Hydrocarbons linear and branched, heavy catalytic cracked (generic) (P-21-111), Hydrocarbons linear and branched, light hydrocracked (generic) (P-21-112), Hydrocarbons linear and branched, isomerization (generic) (P-21-113), Hydrocarbons linear and branched, heavy catalytic reformed (generic) (P-21-114), Hydrocarbons linear and branched, hydrotreated light (generic) (P-21-116), Hydrocarbons linear and branched, hydrotreated light paraffinic (generic) (P-21-117), Hydrocarbons linear and branched, light catalytic cracked (generic) (P-21-118), Hydrocarbons linear and branched, heavy hydrocracked (generic) (P-21-119), Hydrocarbons linear and branched, heavy catalytic cracked (generic) (P-21-121), Hydrocarbons linear and branched, heavy hydrocracked (generic) (P-21-122), and Hydrocarbons linear and branched, light hydrocracked (generic) (P-21-123).

CASRNs: Not available.

Effective Date of TSCA Order: July 14, 2022.

Basis for TSCA Order: The PMNs state that the generic (non-confidential) use will be as a component in fuels (P-21-109, P-21-110, P-21-111, P-21-112, P-21-113, P-21-114, P-21-116, P-21-117, P-21-121, and P-21-123) or as a chemical intermediate (P-21-118, P-21-119, and P-21-122). Based on available information on compositionally analogous mixtures and on constituents of the PMN substances, EPA has identified concerns for skin and eye irritation, acute toxicity, systemic toxicity (neurotoxicity, body weight effects, and liver, kidney, blood, spleen, and other organ effects), reproductive and developmental toxicity, oral and inhalation portal entry effects, genetic toxicity, and carcinogenicity. Based on the chemical composition (petroleum) of the PMN substances, EPA has also identified

concerns for hydrocarbon pneumonia/aspiration hazard. EPA assumes that respiratory tract irritation is possible from exposure to the PMN substances. Based on comparison to analogous chemical substances and data on constituents of the PMN substances, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 0.3 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substances may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No manufacture, processing, or use of the PMN substances other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090;
- Use of personal protective equipment where there is a potential for dermal exposure; and
- Establishment of a hazard communication program.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of skin irritation, eye irritation, respiratory depression/irritation, hydrocarbon developmental toxicity, systemic toxicity, genetic toxicity, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substances. Additionally, the results of consumer inhalation exposure testing/monitoring at gas stations may be potentially useful to characterize the degree of exposure to the PMN substances. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number: P-21-197 (40 CFR 721.11888)

Chemical Name: Imidazole-carboxylic acid, substituted (generic).

CASRN: Not available.

Effective Date of TSCA Order: June 20, 2022.

Basis for TSCA Order: The PMN states that the use will be as an additive for use in battery electrolyte formulations. Based on analogue data, EPA has identified concerns for acute neurotoxicity and skin sensitization. Based on test data for potential metabolites, EPA has also identified concerns for acute toxicity, skin corrosion, eye irritation, and systemic, respiratory tract, reproductive, and developmental effects. Based on acute hazard data for an analogous chemical substance, EPA predicts that toxicity to aquatic organisms may occur at concentrations that exceed 380 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified Combination Particulate and Gas/Vapor respirator with an APF of 50 where there is a potential for inhalation exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS;
- No domestic manufacture of the PMN substance (i.e., import only);
- No processing or use of the PMN substance other than in an enclosed process, except that sampling and equipment cleaning operations need not occur in an enclosed process; and
- No disposal of the PMN substance or waste streams containing the PMN substance other than by incineration with 99.9% efficiency.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity, acute toxicity, metabolism/pharmacokinetics, specific target organ toxicity, skin corrosion, eye damage, skin sensitization, pulmonary effects, reproductive toxicity, and developmental toxicity testing may be potentially useful to characterize the

health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order's restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Numbers: P-21-216 (40 CFR 721.11889) and P-21-217 (40 CFR 721.11890)

Chemical Names: Multi-walled carbon nanotubes (generic) (P-21-216 and P-21-217).

CASRNs: Not available.

Effective Date of TSCA Order: May 31, 2022.

Basis for TSCA Order: The PMNs state that the generic (non-confidential) use will be as an additive in electrode materials and plastics (P-21-216) or as an additive in electrode materials and thermoplastics, and a component in electrodes (P-21-217). Based on comparison to analogous carbon-based nanomaterials, EPA has identified concerns for lung toxicity, lung fibrosis, lung cancer, pleural toxicity (inflammation), pleural fibrosis, and pleural cancer (mesothelioma). Based on hazard data for a residual and test data for multi-walled carbon nanotube analogues, EPA has also identified concerns acute neurotoxicity, skin and respiratory sensitization, reproductive and developmental toxicity, lung effects, systemic effects, immunotoxicity, eye and skin irritation, mutagenicity, genotoxicity, and carcinogenicity. EPA was unable to estimate the environmental hazard of the PMN substances. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substances may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified particulate respirator with an APF of at least 1,000 if the capture and reduction rate is at least 99.5% but not 99.975% or greater, or an APF of at least 50 if the capture and reduction rate is at least 99.975%, where there is a potential for inhalation exposure;
- No domestic manufacture of the PMN substances (i.e., import only);
- No manufacture of the PMN substances to contain the confidential impurity listed in the Order at greater than 1% (by weight);

- No use of the PMN substances other than for the confidential use allowed in the Order;

- No processing or use of the PMN substances other than in application methods that do not generate a vapor, mist, dust, or aerosol unless such application method occurs in an enclosed process;

- No disposal of the PMN substances or waste streams containing the PMN substances other than by landfill or incineration;

- No release of the PMN substances directly, either by point (stack) or non-point (fugitive) sources, to air;

- No release of the PMN substances, or any waste stream containing the PMN substances, into water; and

- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a "significant new use" the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of carcinogenicity, eye irritation, skin irritation, genetic toxicity, developmental toxicity, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substances. Although the Order does not require these tests, the Order's restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

IV. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at <https://www.epa.gov/laws-regulations-and-executive-orders>.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action proposes to establish SNURs for new chemical substances that were the subject of PMNs. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866 (58 FR 51735, October 4, 1993), as amended by Executive Order 14094 (88 FR 21879, April 11, 2023).

B. Paperwork Reduction Act (PRA)

According to the PRA (44 U.S.C. 3501 *et seq.*), an agency may not conduct or sponsor, and a person is not required to respond to a collection of information that requires OMB approval under PRA, unless it has been approved by OMB and displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the CFR, after appearing in the **Federal Register**, are listed in 40 CFR part 9, and included on the related collection instrument or form, if applicable.

The information collection requirements related to SNURs have already been approved by OMB pursuant to PRA under OMB control number 2070-0038 (EPA ICR No. 1188). This action does not impose any burden requiring additional OMB approval. If an entity were to submit a SNUN to the Agency, the annual burden is estimated to average between 30 and 170 hours per submission. This burden estimate includes the time needed to review instructions, search existing data sources, gather and maintain the data needed, and complete, review, and submit the required SNUN.

EPA always welcomes your feedback on the burden estimates. Send any comments about the accuracy of the burden estimate, and any suggested methods for improving the collection instruments or instruction or minimizing respondent burden, including through the use of automated collection techniques.

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 (5 U.S.C. 601 *et seq.*). The requirement to submit a SNUN applies to any person (including small or large entities) who intends to engage in any activity described in the final rule as a "significant new use." Because these uses are "new," based on all information currently available to EPA, EPA has concluded that no small or large entities presently engage in such activities.

A SNUR requires that any person who intends to engage in such activity in the future must first notify EPA by submitting a SNUN. Although some small entities may decide to pursue a significant new use in the future, EPA cannot presently determine how many, if any, there may be. However, EPA's experience to date is that, in response to the promulgation of SNURs covering over 1,000 chemicals, the Agency receives only a small number of notices

per year. For example, the number of SNUNs received was 16 in Federal Fiscal Year (FY) FY2018, five in FY2019, seven in FY2020, 13 in FY2021, 11 in FY2022, and 15 in FY 2023, and only a fraction of these submissions were from small businesses.

In addition, the Agency currently offers relief to qualifying small businesses by reducing the SNUN submission fee from \$37,000 to \$6,480. This lower fee reduces the total reporting and recordkeeping cost of submitting a SNUN to about \$14,500 per SNUN submission for qualifying small firms. Therefore, the potential economic impacts of complying with these proposed SNURs are not expected to be significant or adversely impact a substantial number of small entities. In a SNUR that published in the **Federal Register** of June 2, 1997 (62 FR 29684) (FRL-5597-1), the Agency presented its general determination that SNURs are not expected to have a significant economic impact on a substantial number of small entities, which was provided to the Chief Counsel for Advocacy of the Small Business Administration.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of \$100 million or more in any one year (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. Based on EPA's experience with proposing and finalizing SNURs, State, local, and Tribal governments have not been impacted by SNURs. In addition, the estimated costs of this action to the private sector do not exceed \$183 million or more in any one year (the 1995 dollars are adjusted to 2023 dollars for inflation using the GDP implicit price deflator). The estimated costs for this action are discussed in Unit I.D.

E. Executive Order 13132: Federalism

This action will not have federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999), because it is not expected to have a substantial direct effect on 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. Accordingly, the requirements of Executive Order 13132 do not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action will not have Tribal implications as specified in Executive Order 13175 (65 FR 67249, November 9, 2000), because it is not expected to have substantial direct effects on Indian Tribes, significantly or uniquely affect the communities of Indian Tribal governments and does not involve or impose any requirements that affect Indian Tribes. Accordingly, the requirements of Executive Order 13175 do not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), because it does not concern an environmental health or safety risk. Since this action does not concern human health, EPA's 2021 Policy on Children's Health also does not apply. Although the establishment of these SNURs do not address an existing children's environmental health concern because the chemical uses involved are not ongoing uses, SNURs require that persons notify EPA at least 90 days before commencing manufacture (defined by statute to include import) or processing of any of these chemical substances for an activity that is designated as a significant new use by this rulemaking. This notification allows EPA to assess the conditions of use to identify potential risks and take appropriate actions before the activities commence.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act (NTTAA)

This action does not involve any technical standards subject to NTTAA section 12(d) (15 U.S.C. 272 note).

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

This action does not concern human health or environmental conditions and

therefore cannot be evaluated with respect to the potential for disproportionate impacts on non-white and low-income populations in accordance with Executive Order 12898 (59 FR 7629, February 16, 1994) and Executive Order 14096 (88 FR 25251, April 26, 2023). Although this action does not concern human health or environmental conditions, the premanufacture notifications required by these SNURs allow EPA to assess the conditions of use to identify potential disproportionate risks and take appropriate actions before the activities commence.

List of Subjects in 40 CFR Part 721

Environmental protection, Chemicals, Hazardous substances, Reporting and recordkeeping requirements.

Dated: June 6, 2024.

Mary Elissa Reaves,

Director, Office of Pollution Prevention and Toxics.

Therefore, for the reasons stated in the preamble, EPA proposes to amend 40 CFR chapter 1 as follows:

PART 721—SIGNIFICANT NEW USES OF CHEMICAL SUBSTANCES

■ 1. The authority citation for part 721 continues to read as follows:

Authority: 15 U.S.C. 2604, 2607, and 2625(c)

■ 2. Add §§ 721.11860 through 721.11890 to subpart E to read as follows:

Subpart E—Significant New Uses for Specific Chemical Substances

Sec.

* * * * *

721.11860 1,2-Ethanediamine, N-(1-methylethyl)-N-[2-[(1-methylethyl)amino]ethyl]-.

721.11861 Fatty acids, polymers with substituted carbomonocycles, dialkanolamine, alkyl substituted alkanediamine and halo-substituted heteromonocycle, formates (salts) (generic).

721.11862 Alkanesulfonic acid, 2-[(2-aminoethyl)heteroatom-substituted]-, sodium salt (1:1), polymer with .alpha.-[2,2-bis(hydroxymethyl)butyl]-.omega.-methoxypoly(oxy-1,2-ethanediyl) and 1,1'-methylenebis[4-isocyanatocyclohexane], acrylic acid-dipentaerythritol reaction products- and polypropylene glycol ether with pentaerythritol (4:1) triacrylate-blocked (generic).

721.11863 Alkanoic acid, hydroxy-(hydroxyalkyl)-alkyl-, polymer with .alpha.-[(hydroxyalkyl)alkyl]-.omega.-alkoxypoly(oxy-alkanediyl), (haloalkyl)oxiane polymer (alkylalkylidene)bis[hydroxy-

- carbomonocycle] alkenoate and isocyanate-alkyl-carbomonocycle, hydroxyalkyl acrylate-blocked (generic).
- 721.11864 1,4-Benzenedicarboxylic acid, bis[2-(2-butoxyethoxy)ethyl] ester (9CI).
- 721.11865 Isocyanic acid, polyalkylenepolyarylene ester, polymer with alkyl-hydroxyalkyl-alkanediol, alkoxyalcohol and alkoxyalkoxyalcohol-blocked (generic).
- 721.11866 Substituted alkanolic acid, compound with aminoalkylalkyl-aminoalkylalkoxy-polyoxyalkylalkanediyl, polymer with haloalkyl-epoxide and alkylalkylidene-cycloarylalcohol (generic).
- 721.11867 Bisphenol A epichlorohydrin polymer with alkylpolyalkene-polyarylene-hydroxypolyoxyalkyldiyl reaction products with alkylalkylidenealkylalkylidene-aminoalkyl-alkanepolyamine and alkylaminoalkanol (generic).
- 721.11868 Sulfur based acid, compds. with modified bisphenol A-epichlorohydrin-polyalkylene polyol ether with bisphenol A polymer-N-dialkylalkylidene-N-(dialkylalkylidene)aminoalkyl-alkanepolyamine and heteromonocycle reaction products (generic).
- 721.11869 2-Alkanediol, 3-aryloxy, mono phosphate ester (generic).
- 721.11870 Metalloxanes, alkyl, alkyl group-terminated, reaction products with dihalo-dialkylalkylaryl-alkyl-polycyclic-ylidene(dialkylsilylene)-dialkylalkylaryl-alkylalkyl-polycyclic-ylidene, metal oxide and nonmetallic oxide (generic).
- 721.11871 Alkenoic acid, reaction products with pentaerythritol, polymers with diisocyanatoalkane and heteromonocycle homopolymer esters with alkanolic acid-pentaerythritol reaction products (generic).
- 721.11872 Carbopolycycle octa-alkene, halo (generic).
- 721.11873 2-Propenoic acid, (polyhydro-1,3-dioxo-2H-isoindol-2-yl)alkyl ester (generic).
- 721.11874 Heteromonocycle, polymer, [2-[(1-oxo-2-propen-1-yl)oxy]alkyl]ester (generic).
- 721.11875 Hydrocarbons linear and branched, light alkylate (generic).
- 721.11876 Hydrocarbons linear and branched, light catalytic cracked (generic).
- 721.11877 Hydrocarbons linear and branched, heavy catalytic cracked (generic).
- 721.11878 Hydrocarbons linear and branched, light hydrocracked (generic).
- 721.11879 Hydrocarbons linear and branched, isomerization (generic).
- 721.11880 Hydrocarbons linear and branched, heavy catalytic reformed (generic).
- 721.11881 Hydrocarbons linear and branched, hydrotreated light (generic).
- 721.11882 Hydrocarbons linear and branched, hydrotreated light paraffinic (generic).
- 721.11883 Hydrocarbons linear and branched, light catalytic cracked (generic).
- 721.11884 Hydrocarbons linear and branched, heavy hydrocracked (generic).

- 721.11885 Hydrocarbons linear and branched, heavy catalytic cracked (generic).
- 721.11886 Hydrocarbons linear and branched, heavy hydrocracked (generic).
- 721.11887 Hydrocarbons linear and branched, light hydrocracked (generic).
- 721.11888 Imidazole-carboxylic acid, substituted (generic).
- 721.11889 Multi-walled carbon nanotubes (generic).
- 721.11890 Multi-walled carbon nanotubes (generic).

* * * * *

§ 721.11860 1,2-Ethanediamine, N-(1-methylethyl)-N-[2-[(1-methylethyl)amino]ethyl]-.

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified as 1,2-ethanediamine, N-(1-methylethyl)-N-[2-[(1-methylethyl)amino]ethyl]- (PMN P-18-398; CASRN 10507-06-9) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 50.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity; specific target organ toxicity; reproductive toxicity; skin corrosion; serious eye damage; skin sensitization. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(k).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in

§ 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11861 Fatty acids, polymers with substituted carbomonocycles, dialkanolamine, alkyl substituted alkanediamine and halo-substituted heteromonocycle, formates (salts) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as fatty acids, polymers with substituted carbomonocycles, dialkanolamine, alkyl substituted alkanediamine and halo-substituted heteromonocycle, formates (salts) (PMN P-19-49) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), and (g)(1), (3) and (5). For purposes of § 721.72(e), the concentration is set at 1%. For purposes of § 721.72(g)(1), this substance may cause: skin irritation; eye irritation; reproductive toxicity; specific organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture or process the substance in any manner that generates a vapor, mist, or aerosol. It is a significant new use to use the substance in any manner that generates a vapor, mist, or aerosol that results in inhalation to industrial or commercial workers. It

is a significant new use to manufacture the substance to contain the confidential residual identified in the TSCA Order for this substance at greater than 0.1%.

(iv) *Release to Water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=114.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11862 Alkanesulfonic acid, 2-[(2-aminoethyl)heteroatom-substituted]-, sodium salt (1:1), polymer with .alpha.-[2,2-bis(hydroxymethyl)butyl]-.omega.-methoxypoly(oxy-1,2-ethanediyl) and 1,1'-methylenebis[4-isocyanatocyclohexane], acrylic acid-dipentaerythritol reaction products- and polypropylene glycol ether with pentaerythritol (4:1) triacrylate-blocked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as alkanesulfonic acid, 2-[(2-aminoethyl)heteroatom-substituted]-, sodium salt (1:1), polymer with .alpha.-[2,2-bis(hydroxymethyl)butyl]-.omega.-methoxypoly(oxy-1,2-ethanediyl) and 1,1'-methylenebis[4-isocyanatocyclohexane], acrylic acid-dipentaerythritol reaction products- and polypropylene glycol ether with pentaerythritol (4:1) triacrylate-blocked (PMN P-19-160) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), and (g)(1) and (5). For purposes of § 721.72(g)(1), this substance may cause: skin irritation; eye irritation; serious eye damage; skin sensitization; respiratory sensitization; reproductive toxicity; specific organ

toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(iv) *Release to Water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=302.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11863 Alkanoic acid, hydroxy-(hydroxyalkyl)-alkyl-, polymer with .alpha.-[(hydroxyalkyl)alkyl]-.omega.-alkoxypoly(oxy-alkanediyl), (haloalkyl)oxiane polymer (alkylalkylidene)bis[hydroxy-carbomonocycle] alkenoate and isocyanate-alkyl-carbomonocycle, hydroxyalkyl acrylate-blocked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance generically identified as alkanoic acid, hydroxy-(hydroxyalkyl)-alkyl-, polymer with .alpha.-[(hydroxyalkyl)alkyl]-.omega.-alkoxypoly(oxy-alkanediyl), (haloalkyl)oxiane polymer (alkylalkylidene)bis[hydroxy-carbomonocycle] alkenoate and isocyanate-alkyl-carbomonocycle, hydroxyalkyl acrylate-blocked (PMN P-20-101) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely cured.

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to

prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 50.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity; skin irritation; eye irritation; respiratory sensitization; skin sensitization; reproductive toxicity; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture or process the substance with greater than 20% (by weight) oligomer content below 1,000 daltons (i.e., low molecular weight species). It is a significant new use to use the substance in a manual spray application.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11864 1,4-Benzenedicarboxylic acid, bis[2-(2-butoxyethoxy)ethyl] ester (9CI).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified as 1,4-benzenedicarboxylic acid, bis[2-(2-butoxyethoxy)ethyl] ester (9CI) (PMN P-20-182; CASRN 90430-63-0) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the

operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 1,000.

(A) As an alternative to the respirator requirements in paragraph (a)(2)(i) of this section, a manufacturer or processor may choose to follow the new chemical exposure limit (NCEL) provision listed in the TSCA section 5(e) Order for this substance. The NCEL is 0.01 mg/m³ as an 8-hour time weighted average. Persons who wish to pursue NCELs as an alternative to § 721.63 respirator requirements may request to do so under § 721.30. Persons whose § 721.30 requests to use the NCELs approach are approved by EPA will be required to follow NCELs provisions comparable to those contained in the corresponding TSCA section 5(e) Order.

(B) [Reserved]

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5).

For purposes of § 721.72(g)(1), this substance may cause: skin sensitization; reproductive toxicity; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=4.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (h), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11865 Isocyanic acid, polyalkylenepolyarylene ester, polymer with alkyl-hydroxyalkyl-alkanediol, alkoxyalcohol and alkoxyalkoxyalcohol-blocked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as isocyanic acid, polyalkylenepolyarylene ester, polymer with alkyl-hydroxyalkyl-alkanediol,

alkoxyalcohol and alkoxyalkoxyalcohol-blocked (PMN P-21-56) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured).

(2) The significant new uses are: (i)

Protection in the workplace.

Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 50 or 1,000 if spray applied.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), and (g)(1) and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity; skin sensitization. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture the substance beyond 24 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11866 Substituted alkanolic acid, compound with aminoalkylalkyl-aminoalkylalkoxy-polyoxyalkylalkanedyl, polymer with haloalkyl-epoxide and alkylalkylidene-cycloarylalcohol (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as substituted alkanolic acid, compound with aminoalkylalkyl-aminoalkylalkoxy-

polyoxyalkylalkanedyl, polymer with haloalkyl-epoxide and alkylalkylidene-cycloarylalcohol (PMN P-21-58) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured).

(2) The significant new uses are: (i)

Protection in the workplace.

Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (f), and (g)(1), (3) and (5). For purposes of § 721.72(e), the concentration is set at 1%. For purposes of § 721.72(g)(1), this substance may cause: skin irritation; eye irritation; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=50.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11867 Bisphenol A epichlorohydrin polymer with alkylpolyalkene-polyarylene-hydroxypolyoxyalkyldiyl reaction products with alkylalkylidenealkylalkylidene-aminoalkyl-alkanepolyamine and alkylaminoalkanol (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as bisphenol A epichlorohydrin polymer with alkylpolyalkene-polyarylene-hydroxypolyoxyalkyldiyl reaction products with alkylalkylidenealkylalkylidene-aminoalkyl-alkanepolyamine and alkylaminoalkanol (PMN P-21-60) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), and (g)(1), (3) and (5). For purposes of § 721.72(e), the concentration is set at 0.1%. For purposes of § 721.72(g)(1), this substance may cause: skin irritation; eye irritation; carcinogenicity; reproductive toxicity; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements.* The provisions of subpart A of this part

apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11868 Sulfur based acid, compds. with modified bisphenol A-epichlorohydrin-polyalkylene polyol ether with bisphenol A polymer-N-dialkylalkylidene-N-(dialkylalkylidene)aminoalkyl-alkanepolyamine-alkylaminoalkanol reaction products (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfur based acid, compds. with modified bisphenol A-epichlorohydrin-polyalkylene polyol ether with bisphenol A polymer-N-dialkylalkylidene-N-(dialkylalkylidene)aminoalkyl-alkanepolyamine-alkylaminoalkanol reaction products (PMN P-21-61) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), and (g)(1), (3) and (5). For purposes of § 721.72(e), the concentration is set at 0.1%. For purposes of § 721.72(g)(1), this substance may cause: skin irritation; eye irritation; carcinogenicity; reproductive toxicity; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=11.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11869 1,2-Alkanediol, 3-aryloxy, mono phosphate ester (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as 1,2-alkanediol, 3-aryloxy, mono phosphate ester (PMN P-21-66) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely destroyed.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), and (g)(1), (3) and (5). For the purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause: acute toxicity; skin corrosion; skin irritation; serious eye damage; eye irritation; reproductive toxicity; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA

Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure or that results in fugitive air emissions. It is a significant new use to use the substance other than as an epoxy curative.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11870 Metalloxanes, alkyl, alkyl group-terminated, reaction products with dihalo-dialkylalkylaryl-alkyl-polycyclic-ylidene(dialkylsilylene)-dialkylalkylaryl-alkylalkyl-polycyclic-ylidene, metal oxide and nonmetallic oxide (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as metalloxanes, alkyl, alkyl group-terminated, reaction products with dihalo-dialkylalkylaryl-alkyl-polycyclic-ylidene(dialkylsilylene)-dialkylalkylaryl-alkylalkyl-polycyclic-ylidene, metal oxide and nonmetallic oxide (PMN P-21-68) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), and (g)(1) and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity; skin corrosion; skin irritation; serious eye damage; eye irritation; respiratory

sensitization; skin sensitization; germ cell mutagenicity; reproductive toxicity; specific target organ toxicity.

Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(a) through (c). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation or dermal exposure.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=50.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11871 Alkenoic acid, reaction products with pentaerythritol, polymers with diisocyanatoalkane and heteromonocycle homopolymer esters with alkenoic acid-pentaerythritol reaction products (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as alkenoic acid, reaction products with pentaerythritol, polymers with diisocyanatoalkane and heteromonocycle homopolymer esters with alkenoic acid-pentaerythritol reaction products (PMN P-21-83) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators

must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 1,000.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5).

For purposes of § 721.72(g)(1), this substance may cause: skin irritation; eye irritation; respiratory sensitization; skin sensitization; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o).

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=1.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11872 Carbopolycycle octa-alkene, halo (generic).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified generically as carbopolycycle octa-alkene, halo (PMN P-21-84) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 50.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a)

through (d), (f), and (g)(1), (3) and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity; skin corrosion; serious eye damage; skin sensitization; genetic toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=7.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (h), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11873 2-Propenoic acid, (polyhydro-1,3-dioxo-2H-isoindol-2-yl)alkyl ester (generic).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified generically as 2-propenoic acid, (polyhydro-1,3-dioxo-2H-isoindol-2-yl)alkyl ester (PMN P-21-92) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the PMN substance after they have been completely reacted (cured).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (a)(4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 1.0%. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 10.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), and (g)(1) and (3). For

purposes of § 721.72(g)(1), this substance may cause: skin irritation; eye irritation; specific target organ toxicity; reproductive toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. For purposes of § 721.72(e), the concentration is set at 1.0%. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to use the substance at a concentration of greater than 40% in formulation when inhalation exposure is expected.

(iv) *Disposal.* It is a significant new use to dispose of the substance or waste streams containing the substance other than by incineration or RCRA subtitle C landfill.

(v) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11874 Heteromonocycle, polymer, [2-[(1-oxo-2-propen-1-yl)oxy]alkyl]ester (generic).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified generically as heteromonocycle, polymer, [2-[(1-oxo-2-propen-1-yl)oxy]alkyl]ester (PMN P-21-102) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures)

shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 10.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5). For purposes of § 721.72(g)(1), this substance may cause: skin irritation; eye irritation; specific target organ toxicity; developmental toxicity; skin sensitization. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o).

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=337.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11875 Hydrocarbons linear and branched, light alkylate (generic).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified generically as hydrocarbons linear and branched, light alkylate (PMN P-21-109) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative

control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11876 Hydrocarbons linear and branched, light catalytic cracked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, light catalytic cracked (PMN P-21-110) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11877 Hydrocarbons linear and branched, heavy catalytic cracked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, heavy catalytic cracked (PMN P-21-111) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel

blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11878 Hydrocarbons linear and branched, light hydrocracked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, light hydrocracked (PMN P-21-112) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part

apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11879 Hydrocarbons linear and branched, isomerization (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, isomerization (PMN P-21-113) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11880 Hydrocarbons linear and branched, heavy catalytic reformed (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, heavy catalytic reformed (PMN P-21-114) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11881 Hydrocarbons linear and branched, hydrotreated light (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, hydrotreated light (PMN P-21-116) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11882 Hydrocarbons linear and branched, hydrotreated light paraffinic (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, hydrotreated light paraffinic

(PMN P-21-117) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11883 Hydrocarbons linear and branched, light catalytic cracked (generic).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance generically identified as hydrocarbons linear and branched, light catalytic cracked (PMN P-21-118) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery

feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11884 Hydrocarbons linear and branched, heavy hydrocracked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, heavy hydrocracked (PMN P-21-119) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are

reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11885 Hydrocarbons linear and branched, heavy catalytic cracked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, heavy catalytic cracked (PMN P-21-121) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent

exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11886 Hydrocarbons linear and branched, heavy hydrocracked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, heavy hydrocracked (PMN P-21-122) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant

new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11887 Hydrocarbons linear and branched, light hydrocracked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as hydrocarbons linear and branched, light hydrocracked (PMN P-21-123) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel, fuel additive, fuel blending stock, or used as a refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting).

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture, process, or use the substance other than for processing and use as a fuel, fuel additive, fuel blending stock, or refinery feedstock (including, but not limited to cracking, coking, hydroprocessing, distillation, or deasphalting) subject to 40 CFR parts 79 or 1090.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11888 Imidazole-carboxylic acid, substituted (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as imidazole-carboxylic acid, substituted (P-21-197) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into an article.

(2) The significant new uses are: (i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 50.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity; skin corrosion; eye irritation; serious eye damage; skin sensitization; reproductive toxicity; specific target organ toxicity. For purposes of § 721.72(g)(3) this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f). It is a significant new use to process or use the substance other than in an enclosed process, except that sampling and equipment

cleaning operations need not occur in an enclosed process.

(iv) *Disposal*. It is a significant new use to dispose of the substance or waste streams containing the substance other than by incineration with 99.9% efficiency.

(b) *Specific requirements*. The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping*. Recordkeeping requirements as specified in § 721.125(a) through (j) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements*. The provisions of § 721.185 apply to this section.

§ 721.11889 Multi-walled carbon nanotubes (generic).

(a) *Chemical substance and significant new uses subject to reporting*.

(1) The chemical substance identified generically as multi-walled carbon nanotubes (PMN P-21-216) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted (cured), entrained in a polymer, or incorporated into an article.

(2) The significant new uses are: (i) *Protection in the workplace*. Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 1,000 if the capture and reduction rate is at least 99.5% but not 99.975% or greater, or at least 50 if the capture and reduction rate is at least 99.975%.

(ii) *Hazard communication*. Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5). For purposes of § 721.72(g)(1), this substance may cause: eye irritation; skin

irritation; respiratory sensitization; skin sensitization; genetic toxicity; reproductive toxicity; carcinogenicity; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities*. Requirements as specified in § 721.80(f). It is a significant new use to manufacture the substance to contain the confidential impurity listed in the Order at greater than 1% (by weight). It is a significant new use to process or use the substance other than for the confidential use allowed in the Order. It is a significant new use to process or use the substance other than in application methods that do not generate a vapor, mist, dust, or aerosol, unless such application method occurs in an enclosed process.

(iv) *Disposal*. Requirements as specified in § 721.85 (a)(1) and (2), (b)(1) and (2), and (c)(1) and (2). It is a significant new use to release the substance directly, whether by point (stack) or non-point (fugitive) sources, to air.

(v) *Release to water*. Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements*. The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping*. Recordkeeping requirements as specified in § 721.125(a) through (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements*. The provisions of § 721.185 apply to this section.

§ 721.11890 Multi-walled carbon nanotubes (generic).

(a) *Chemical substance and significant new uses subject to reporting*.

(1) The chemical substance identified generically as multi-walled carbon nanotubes (PMN P-21-217) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted

(cured), entrained in a polymer, or incorporated into an article.

(2) The significant new uses are:

(i) *Protection in the workplace*.

Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 1,000 if the capture and reduction rate is at least 99.5% but not 99.975% or greater or of at least 50 if the capture and reduction rate is at least 99.975%.

(ii) *Hazard communication*.

Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5). For purposes of § 721.72(g)(1), this substance may cause: eye irritation; skin irritation; respiratory sensitization; skin sensitization; genetic toxicity; reproductive toxicity; carcinogenicity; specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities*. Requirements as specified in § 721.80(f). It is a significant new use to manufacture the substance to contain the confidential impurity listed in the Order at greater than 1% (by weight). It is a significant new use to process or use the substance other than for the confidential use allowed in the Order. It is a significant new use to process or use the substance other than in application methods that do not generate a vapor, mist, dust, or aerosol, unless such application method occurs in an enclosed process.

(iv) *Disposal*. Requirements as specified in § 721.85 (a)(1) and (2), (b)(1) and (2), and (c)(1) and (2). It is a significant new use to release the substance directly, either by point (stack) or non-point (fugitive) sources, to air.

(v) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The

provisions of § 721.185 apply to this section.

* * * * *

[FR Doc. 2024–12764 Filed 6–10–24; 8:45 am]

BILLING CODE 6560–50–P

Notices

Federal Register

Vol. 89, No. 113

Tuesday, June 11, 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

Agricultural Marketing Service

[Doc. No. AMS–SC–24–0005]

Notice of Request for Extension and Revision of a Currently Approved Information Collection

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Notice and request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice announces the Agricultural Marketing Service's (AMS) intention to request approval from the Office of Management and Budget (OMB) for an extension of and revision to the currently approved information collection 0581–0328 for the Pecan Promotion, Research, and Information Program.

DATES: Comments must be received by August 12, 2024 to be assured of consideration.

ADDRESSES: Interested persons are invited to submit written comments concerning this notice. Comments may be mailed to the Docket Clerk, Market Development Division, Specialty Crops Program, AMS, USDA, 1400 Independence Avenue SW, STOP 0237, Washington, DC 20250–0237; Fax: (202) 720–8938; or submitted electronically by Email: SM.USDA.MRP.AMS.MDDComment@usda.gov; or via internet at <https://www.regulations.gov>. Comments should reference the document number and the date and page number of this issue of the **Federal Register**. All comments will be made available for public inspection in the Office of the Docket Clerk during regular business hours or can be viewed at <https://www.regulations.gov>. Comments submitted in response to this notice will be included in the rulemaking record and will be made

available to the public. Please be advised that the identity of the individuals or entities submitting the comments will be made public.

FOR FURTHER INFORMATION CONTACT:

Katie Cook, Marketing Specialist at telephone: (202) 617–4760, or electronic mail: Katie.Cook@usda.gov, or Sarah Richardson, Marketing Specialist at telephone: (202) 720–8085 electronic mail: Sarah.Richardson@usda.gov, Market Development Division, Specialty Crops Program, AMS, USDA, Stop 0244, Room 1406–S, 1400 Independence Avenue SW, Washington, DC 20250–0244.

SUPPLEMENTARY INFORMATION:

Title: Pecan Promotion, Research, and Information Program.

OMB Number: 0581–0328.

Expiration Date of Approval: October 31, 2024.

Type of Request: Extension and revision of a currently approved information collection.

Abstract: The Pecan Promotion, Research, and Information program was created to help strengthen the position of pecans in the marketplace, maintain and expand markets for pecans, and develop new uses for pecans. The Pecan Promotion, Research, and Information Order (Order) (7 CFR part 1223) is authorized under the Commodity Promotion, Research, and Information Act of 1996 (1996 Act) (7 U.S.C. 7411–7425).

The Order became effective on February 12, 2021. Currently, the Pecan program is administered by the American Pecan Promotion Board (Board) which is appointed by the Secretary of Agriculture and financed by a mandatory assessment on producers and importers of inshell and shelled pecans. The assessment rate is levied at \$0.02 per pound on all inshell pecans and \$0.04 per pound on all shelled pecans. The program provides an exemption for producers and importers that produce or import fewer than 50,000 pounds of inshell pecans (25,000 pounds of shelled pecans) on average for four fiscal periods (the fiscal period for which the exemption is claimed and the previous three fiscal periods).

The information collection requirements in this request are essential to carry out the intent of the 1996 Act and the Order. The objective in carrying out this responsibility includes assuring the following: (1)

funds are collected and properly accounted for; (2) expenditures of all funds are for the purposes authorized by the 1996 Act and Order; and (3) the board's administration of the programs conforms to USDA policy. Such information can be supplied without data processing equipment or outside technical expertise. In addition, there are no additional training requirements for individuals filling out reports and remitting assessments to the Board.

The Board utilizes a variety of forms including: first handler and importer reports, application for exemption, nomination form and ballot, reimbursement of assessments, and recordkeeping requirements and prefers electronic versions of the forms for easier access and submission.

The information collected is used only by authorized representatives of the USDA's regional and headquarters staff, and authorized Board employees. Authorized Board employees and the industry are the primary users of the information, and AMS is the secondary user.

Estimate of Burden: Public recordkeeping burden for this collection of information is estimated to average 0.43 hour per response.

Respondents: Producers and importers.

Estimated Number of Respondents: 725.

Estimated Total Annual Responses: 10,718.

Estimated Number of Responses per Respondent: 2.

Estimated Total Annual Burden on Respondents: 2,873 hours.

Comments: Comments are invited on: (1) 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; (2) 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; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

All responses to this notice will be summarized and included in the request

for OMB approval. All comments will also become a matter of public record.
Authority: 44 U.S.C. chapter 35.

Erin Morris,

Associate Administrator, Agriculture Marketing Service.

[FR Doc. 2024-12673 Filed 6-10-24; 8:45 am]

BILLING CODE P

DEPARTMENT OF AGRICULTURE

Forest Service

Modoc Resource Advisory Committee

AGENCY: Forest Service, Agriculture (USDA).

ACTION: Notice of meeting.

SUMMARY: The Modoc Resource Advisory Committee will hold a public meeting according to the details shown below. The committee is authorized under the Secure Rural Schools and Community Self-Determination Act (the Act) and operates in compliance with the Federal Advisory Committee Act. The purpose of the committee is to improve collaborative relationships and to provide advice and recommendations to the Forest Service concerning projects and funding consistent with title II of the Act, as well as make recommendations on recreation fee proposals for sites on the Modoc National Forest within Modoc County, consistent with the Federal Lands Recreation Enhancement Act.

DATES: An in-person and virtual meeting will be held on June 26, 2024, at 3 p.m. Pacific daylight time (PDT).

Written and Oral Comments: Anyone wishing to provide in-person or virtual oral comments must pre-register by 11:59 p.m. (PDT) on June 12, 2024. Written public comments will be accepted by 11:59 p.m. (PDT) on June 12, 2024. Comments submitted after this date will be provided by the Forest Service to the committee, but the committee may not have adequate time to consider those comments prior to the meeting.

All committee meetings are subject to cancellation. For status of the meeting prior to attendance, please contact the person listed under **FOR FURTHER INFORMATION CONTACT**.

ADDRESSES: This meeting will be held in-person at the Modoc National Forest Supervisor's Office conference room, located at 225 West 8th Street, Alturas, California 96101. The public may also join the meeting virtually via webcast, teleconference, videoconference, or the Homeland Security Information Network. Resource advisory committee information and meeting details can be

found on the advisory committee website at www.fs.usda.gov/main/modoc/workingtogether/advisorycommittees or by contacting the person listed under **FOR FURTHER INFORMATION CONTACT**.

Written Comments: Written comments must be sent by email to samantha.jager@usda.gov or via mail (postmarked) to Resource Advisory Committee Coordinator, 225 West 8th Street, Alturas, California 96101. The Forest Service strongly prefers comments be submitted electronically.

Oral Comments: Persons or organizations wishing to make oral comments must pre-register by 11:59 p.m. PDT, June 12, 2024, and speakers can only register for one speaking slot. Oral comments must be sent by email to samantha.jager@usda.gov or via mail (postmarked) to Resource Advisory Committee Coordinator, 225 West 8th Street, Alturas, California 96101.

FOR FURTHER INFORMATION CONTACT: Chris Christofferson, Designated Federal Officer, at 530-233-5811 or email at chris.christofferson@usda.gov; or Samantha Jager, Resource Advisory Committee Coordinator, at 530-708-7291 or email at samantha.jager@usda.gov.

SUPPLEMENTARY INFORMATION: The purpose of the meeting is to:

1. Discuss any old business from last year;
2. Hear from Title II project proponents and discuss Title II project proposals;
3. Make funding recommendations on Title II projects;
4. Discuss committee vacancies;
5. Approve meeting minutes;
6. Schedule the next meeting.

The agenda will include time for individuals to make oral statements of three minutes or less. To be scheduled on the agenda, individuals wishing to make an oral statement should make a request in writing at least three days prior to the meeting date. Written comments may be submitted to the Forest Service up to 14 days after the meeting date listed under **DATES**.

Please contact the person listed under **FOR FURTHER INFORMATION CONTACT**, by or before the deadline, for all questions related to the meeting. All comments, including names and addresses when provided, are placed in the record and are available for public inspection and copying. The public may inspect comments received upon request.

Meeting Accommodations: The meeting location is compliant with the Americans with Disabilities Act, and the USDA provides reasonable accommodation to individuals with

disabilities where appropriate. If you are a person requiring reasonable accommodation, please make requests in advance for sign language interpretation, assistive listening devices, or other reasonable accommodation to the person listed under the **FOR FURTHER INFORMATION CONTACT** section or contact USDA's TARGET Center at 202-720-2600 (voice and TTY) or USDA through the Federal Relay Service at 800-877-8339. Additionally, program information may be made available in languages other than English.

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/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.

Equal opportunity practices in accordance with USDA's policies will be followed in all appointments to the committee. To ensure that the recommendations of the Committee have taken into account the needs of the diverse groups served by the Department, membership shall include, to the extent practicable, individuals with demonstrated ability to represent the many communities, identities, races, ethnicities, backgrounds, abilities, cultures, and beliefs of the American people, including underserved communities. USDA is an equal opportunity provider, employer, and lender.

Dated: May 29, 2024.

Cikena Reid,

USDA Committee Management Officer.

[FR Doc. 2024-12130 Filed 6-10-24; 8:45 am]

BILLING CODE 3411-15-P

COMMISSION ON CIVIL RIGHTS

Notice of Public Meeting of the North Carolina Advisory Committee to the U.S. Commission on Civil Rights

AGENCY: U.S. Commission on Civil Rights.

ACTION: Notice of Public Meeting.

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, that

the North Carolina Advisory Committee (Committee) to the U.S. Commission on Civil Rights will hold a public community forum via Zoom at 6:00 p.m. ET on Thursday, June 27, 2024. The purpose of this forum is to hear from members of the public regarding their experience with the child welfare system in North Carolina. Members of the public who would like to participate in the forum should complete this form by Wednesday, June 26, 2024, to ensure they are added to the list of interested speakers: <https://forms.monday.com/forms/d1617eeebc0e76fcbcf803289c4b5757?r=use1>.

DATES: Thursday, June 27, 2024, from 6:00 p.m.–8:00 p.m. Eastern Time.

ADDRESSES: The meeting will be held via Zoom Webinar.

Registration Link (Audio/Visual):
https://www.zoomgov.com/webinar/register/WN_92khkxC1SFS_dfikVHfwDg.

Join by Phone (Audio Only): (833) 435–1820 USA Toll-Free; Meeting ID: 161 265 0808.

FOR FURTHER INFORMATION CONTACT:

Victoria Moreno, Designated Federal Officer, at vmoreno@usccr.gov or (434) 515–0204.

SUPPLEMENTARY INFORMATION: This committee meeting is available to the public through the registration 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. Callers will incur no charge for calls they initiate over land-line connections to the toll-free telephone number. Closed captioning will be available for individuals who are deaf, hard of hearing, or who have certain cognitive or learning impairments. To request additional accommodations, please email Liliana Schiller, Support Services Specialist, at lschiller@usccr.gov at least 10 business days prior to the meeting.

Members of the public are entitled to submit written comments; the comments must be received in the regional office within 30 days following the meeting. Written comments may be emailed to Victoria Moreno at vmoreno@usccr.gov. Persons who desire additional information may contact the

Regional Programs Coordination Unit at (312) 353–8311.

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, North Carolina 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 lschiller@usccr.gov.

Agenda

- I. Welcome & Roll Call
- II. Community Forum
- III. Next Steps
- IV. Adjournment

Dated: June 6, 2024.

David Mussatt,

Supervisory Chief, Regional Programs Unit.

[FR Doc. 2024–12737 Filed 6–10–24; 8:45 am]

BILLING CODE P

DEPARTMENT OF COMMERCE

Economic Development Administration

Submission for OMB Review; Comment Request; Agency Information Collection Activities; Submission to the Office of Management and Budget (OMB) for Review and Approval; Comment Request; Indigenous Communities Survey & Interview Collection Instruments

The Department of Commerce will submit the following information collection request to the Office of Management and Budget (OMB) for review and clearance in accordance with the Paperwork Reduction Act of 1995, on or after the date of publication of this notice. We invite 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. Public comments were previously requested via the **Federal Register** on March 29, 2024 during a 60-day comment period. This notice allows for an additional 30 days for public comments.

Agency: Economic Development Administration (EDA), Commerce.

Title: Indigenous Communities Survey & Interview Collection Instruments.

OMB Control Number: New information collection.

Form Number(s): None yet determined; new information collection.

Type of Request: Regular submission.

Estimated Number of Respondents and Frequency: A total of 150 respondents will complete a survey. Additional phone interviews will be conducted with a subset of 20 survey respondents. The proposed information collection will be conducted once. As the Community of Practice and Research Challenge to Support Indigenous Communities is a new cooperative agreement, EDA anticipates that these estimates will be further refined based on data generated completed survey respondents.

Estimated Average Hours per Response: Half an hour (30 minutes) for the electronic survey and 1 hour for each phone interview.

Estimated Burden Hours: 75 hours for the electronic survey and 20 hours for the phone interviews.

Needs and Uses: To effectively administer and monitor its economic development assistance programs, EDA collects certain information from applications for, and recipients of, EDA investment assistance. The purpose of this notice is to seek comments from the public and other Federal agencies on a request for a new information collection for recipients of awards under the EDA American Rescue Plan Act (ARPA) Statewide Planning, Research, and Networks, and Economic Development Research and Evaluation (R&E) and National Technical Assistance (NTA) programs.

The proposed information collection will employ an innovative mixed methods approach to gather traditional metrics in addition to qualitative data on Indigenous or Indigenous-serving projects. An annual survey will be sent to Indigenous or Indigenous-serving grantees from 2019–2023 resulting in factsheets and reports that will help inform economic development policy, economic decision-making, and economic best practices.

The collection will explore several thematic areas for Indigenous communities, each based on the following research questions:

1. How has EDA funded Indigenous-serving projects and what are the characteristics of these projects relative to applications from Indigenous entities;
2. What factors relate to project implementation and outputs for awards to Indigenous applicants and for Indigenous-serving projects;
3. How did the structure of the Indigenous Communities funding program influence applicants and award

decisions relative to Indigenous applicants to other funding programs; and

4. How do grant rates influence applications from Indigenous entities and applications from Indigenous-serving organizations with projects benefitting Indigenous communities;

With each of these categories of questions, organized by thematic area and noted above, there will be a focus on learning about the economic development needs, planning, and priorities of Indigenous communities.

Respondents will answer questions related to the following:

- Community characteristics;
- Economic development characteristics, priorities, challenges;
- Economic development funding sources;
- Match funding; and
- If applicable, the Indigenous Communities grant program.

The collection instrument also includes questions related to the overall programmatic experience.

Affected Public: This survey will specifically target EDA applicants for projects that are Indigenous and Indigenous serving. Entities may include (i) District Organization of an EDA-designated Economic Development District (EDD); (ii) Indian Tribe or a consortium of Indian Tribes; (iii) State, county, city, or other political subdivision of a State, including a special purpose unit of a State or local government engaged in economic or infrastructure development activities, or a consortium of political subdivisions; (iv) institution of higher education or a consortium of institutions of higher education; or (v) public or private non-profit organization or association acting in cooperation with officials of a general purpose political subdivision of a State.

Respondent's Obligation: Voluntary.

Legal Authority: The Public Works and Economic Development Act of 1965 (42 U.S.C. 3121 *et seq.*).

This information collection request may be viewed at [reginfo.gov](https://www.reginfo.gov). Follow the instructions to view Department of Commerce collections currently under review by OMB.

Written comments and recommendations for the proposed information collection should be submitted within 30 days of the publication of this notice on the following website www.reginfo.gov/public/do/PRAMain. Find this particular information collection by

selecting “Currently under 30-day Review—Open for Public Comments.”

Sheleen Dumas,

Department PRA Clearance Officer, Office of the Under Secretary for Economic Affairs, Commerce Department.

[FR Doc. 2024–12769 Filed 6–10–24; 8:45 am]

BILLING CODE 3510–34–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–954]

Certain Magnesia Carbon Bricks From the People's Republic of China: 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) is rescinding the administrative review of the antidumping duty order on certain magnesia carbon bricks (bricks) from the People's Republic of China (China) for the period of review (POR) September 1, 2022, through August 31, 2023.

DATES: Applicable June 11, 2024.

FOR FURTHER INFORMATION CONTACT: Nathan James, AD/CVD Operations, Office V, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–5305.

SUPPLEMENTARY INFORMATION:

Background

On September 20, 2010, Commerce published in the **Federal Register** the antidumping duty order on bricks from China.¹ On September 28, 2023, the Magnesia Carbon Bricks Fair Trade Committee (the petitioner) submitted a timely request that Commerce conduct an administrative review.²

On November 15, 2023, Commerce published in the **Federal Register** a notice of initiation of administrative review with respect to imports of bricks from China in accordance with section 751(a) of the Tariff Act of 1930, as amended (the Act) and 19 CFR 351.221(c)(1)(i).³ This review covers subject merchandise exported by 42

exporters.⁴ On December 20, 2023, we placed on the record U.S. Customs and Border Protection (CBP) data for entries of bricks from China during the POR, showing no reviewable POR entries and invited interested parties to comment.⁵ No party filed comments with respect to the CBP data.

On February 7, 2024, Commerce notified all interested parties of its intent to rescind the instant review because there were no reviewable, suspended entries of subject merchandise by any of the companies subject to this review during the POR and invited interested parties to comment.⁶ Commerce did not receive any comments.

Rescission of Review

Pursuant to 19 CFR 351.213(d)(3), it is Commerce's practice to rescind an administrative review of an antidumping duty order when there are no reviewable entries of subject merchandise during the POR for which liquidation is suspended.⁷ Normally, upon completion of an administrative review, the suspended entries are liquidated at the antidumping duty assessment rate calculated for the review period.⁸ Therefore, for an administrative review to be conducted, there must be a reviewable, suspended entry that Commerce can instruct CBP to liquidate at the antidumping duty assessment rate calculated for the review period.⁹ As noted above, there were no entries of subject merchandise for the companies subject to this review during the POR. Accordingly, in the absence of suspended entries of subject merchandise during the POR, we are hereby rescinding this administrative review, in its entirety, in accordance with 19 CFR 351.213(d)(3).

Assessment

Commerce will instruct CBP to assess antidumping duties on all appropriate entries. Antidumping duties shall be assessed at rates equal to the cash deposit of estimated antidumping duties required at the time of entry, or

⁴ *Id.*

⁵ See Memorandum, “Release of Customs and Border Protection Data Query,” dated December 20, 2023.

⁶ See Memorandum, “Notice of Intent to Rescind Review,” dated February 7, 2024.

⁷ See, e.g., *Diocetyl Terephthalate from the Republic of Korea: Rescission of Antidumping Administrative Review; 2021–2022*, 88 FR 24758 (April 24, 2023); see also *Certain Carbon and Alloy Steel Cut-to-Length Plate from the Federal Republic of Germany: Rescission of Antidumping Administrative Review; 2020–2021*, 88 FR 4154 (January 24, 2023).

⁸ See 19 CFR 351.212(b)(1).

⁹ See 19 CFR 351.213(d)(3).

¹ See *Certain Magnesia Carbon Bricks from Mexico and the People's Republic of China: Antidumping Duty Orders*, 75 FR 57257 (September 20, 2010) (Order).

² See Petitioner's Letter, “Request for Administrative Review,” dated September 28, 2023.

³ See *Initiation of Antidumping and Countervailing Duty Administrative Reviews*, 88 FR 78298 (November 15, 2023).

withdrawal from warehouse, for consumption in the United States, in accordance with 19 CFR 351.212(c)(1)(i). Commerce intends to issue assessment instructions to CBP no earlier than 35 days after the date of publication of this rescission notice in the **Federal Register**.

Administrative Protective Order

This notice serves as the only reminder to parties subject to an administrative protective order (APO) of their responsibility concerning the disposition 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

This notice is issued and published in accordance with sections 751(a)(1) and 777(i)(1) of the Act, and 19 CFR 351.213(d)(4).

Dated: May 29, 2024.

James Maeder,

Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations.

[FR Doc. 2024–12742 Filed 6–10–24; 8:45 am]

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DEPARTMENT OF COMMERCE

International Trade Administration

[C–570–991]

Chlorinated Isocyanurates From the People's Republic of China: Final Results of Countervailing Duty Administrative Review; 2021

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) determines that countervailable subsidies are being provided to the producers and exporters subject to the administrative review of chlorinated isocyanurates (chlorinated isos) from the People's Republic of China (China) during the period of review (POR) January 1, 2021, through December 31, 2021.

DATES: Applicable June 11, 2024.

FOR FURTHER INFORMATION CONTACT: Miranda Bourdeau or Eliza DeLong, AD/CVD Operations, Office V, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone:

(202) 482–2021 or (202) 482–3878, respectively.

SUPPLEMENTARY INFORMATION:

Background

On December 7, 2023, Commerce published the preliminary results of the 2021 administrative review of the countervailing duty order on chlorinated isos from China.¹ This review covers two companies, Heze Huayi Chemical Co., Ltd. (Heze Huayi) and Juancheng Kangtai Chemical Co., Ltd. We invited interested parties to comment on the *Preliminary Results*.² On March 27, 2024, we extended the deadline for these final results until June 4, 2024, in accordance with section 751(a)(3)(A) of the Tariff Act of 1930, as amended (the Act).³ For a complete description of the events that occurred since the *Preliminary Results*, see the Issues and Decision Memorandum.⁴

Scope of the Order⁵

The products covered by the *Order* are chlorinated isos from China. A full description of the scope of the *Order* is provided in the Issues and Decision Memorandum.

Analysis of Comments Received

A list of the issues that parties raised, to which we responded in the Issues and Decision Memorandum, is attached as an 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>.

¹ See *Chlorinated Isocyanurates from the People's Republic of China: Preliminary Results of the Countervailing Duty Administrative Review and Rescission of Review in Part; 2021*, 88 FR 85214 (December 7, 2023) (*Preliminary Results*), and accompanying Preliminary Decision Memorandum (PDM).

² See *Preliminary Results*, 88 FR at 85216.

³ See Memorandum, “Extension of Deadline for Final Results of Countervailing Duty Administrative Review,” dated March 27, 2024.

⁴ See Memorandum, “Decision Memorandum for the Final Results of the Countervailing Duty Administrative Review of Chlorinated Isocyanurates from the People's Republic of China; 2021,” dated concurrently with, and hereby adopted by, this notice (Issues and Decision Memorandum).

⁵ See *Chlorinated Isocyanurates from the People's Republic of China: Countervailing Duty Order*, 79 FR 67424 (November 13, 2014) (*Order*).

Changes Since the Preliminary Results

Based on arguments raised and a review of the record and all supporting documentation, we made certain changes to the *Preliminary Results* with respect to the subsidy rate calculation for the provision of land-use rights for less than adequate remuneration for the chemical industry program. For a discussion of the comments, see the Issues and Decision Memorandum.

Methodology

Commerce conducted this administrative review in accordance with section 751(a)(1)(A) of the Act. For each subsidy program found to be countervailable, Commerce finds that there is a subsidy, *i.e.*, a financial contribution from a government or public entity that gives rise to a benefit to the recipient, and that the subsidy is specific.⁶ For a full description of the methodology underlying all of Commerce's conclusions, including any determination that relied upon the use of adverse facts available pursuant to sections 776(a) and (b) of the Act, see the Issues and Decision Memorandum.

Company Not Selected for Individual Review

We made no changes to the methodology for determining the rate assigned to Sincere Cooperation Material, the company not selected for individual examination, from the *Preliminary Results*.⁷ However, we revised this rate to reflect the changes to Heze Huayi's rate.⁸

Final Results of Administrative Review

In accordance with 19 CFR 351.221(b)(5), Commerce calculated the following net countervailable subsidy rates for the period January 1, 2021, through December 31, 2021:

Company	Subsidy rate (percent <i>ad valorem</i>)
Heze Huayi Chemical Co., Ltd.	3.12
Juancheng Kangtai Chemical Co., Ltd.	3.96
Review-Specific Average Rate Applicable to the Following Company	
Sincere Cooperation Material	3.26

⁶ See sections 771(5)(B) and (D) of the Act regarding financial contribution; section 771(5)(E) of the Act regarding benefit; and section 771(5A) of the Act regarding specificity.

⁷ See *Preliminary Results* PDM at 5.

⁸ See Memorandum, “Calculation of Subsidy Rate for Non-Selected Companies Under Review,” dated concurrently with this notice.

Disclosure

Commerce will disclose to interested parties the calculations performed for these final results within five days of 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).

Assessment

Pursuant to section 751(a)(2)(C) of the Act and 19 CFR 351.212(b)(2), Commerce will determine, and U.S. Customs and Border Protection (CBP) shall assess, countervailing duties on all appropriate entries of subject merchandise in accordance with the final results of this review, for the above-listed companies at the applicable *ad valorem* assessment rates listed. We intend to issue assessment instructions to CBP no earlier than 35 days after the date of publication of these final results of review. 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).

Cash Deposit Requirements

In accordance with section 751(a)(1) of the Act, Commerce intends to instruct CBP to collect cash deposits of estimated countervailing duties in the amounts shown for each of the respective companies listed above on shipments of subject merchandise entered, or withdrawn from warehouse, for consumption on or after the date of publication of the final results of this administrative review. For all non-reviewed firms subject to the *Order*, we will instruct CBP to continue to collect cash deposits of estimated countervailing duties at the most recent company-specific or all-others rate applicable to the company, as appropriate. These cash deposit requirements, effective upon publication of the final results of this review, shall remain in effect until further notice.

Administrative Protective Order

This notice also serves as a final 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

Commerce is issuing and publishing the final results of review in accordance with sections 751(a)(1) and 777(i)(1) of the Act and 19 CFR 351.221(b)(5).

Dated: June 4, 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. Subsidies Valuation Information
- V. Benchmarks
- VI. Use of Facts Otherwise Available and Application of Adverse Inferences
- VII. Analysis of Programs
- VIII. Discussion of the Issues
 - Comment 1: Whether Commerce Should Apply Adverse Facts Available to the Program on the Provision of Land-Use Rights for Less Than Adequate Remuneration for the Chemical Industry
 - Comment 2: Whether Commerce Should Include Land-Use Rights Acquired Outside the AUL Period in its Benefit Calculation
- IX. Recommendation

[FR Doc. 2024-12739 Filed 6-10-24; 8:45 am]

BILLING CODE 3510-DS-P

DEPARTMENT OF COMMERCE

International Trade Administration

[A-520-804]

Certain Steel Nails From the United Arab Emirates: Preliminary Results of Antidumping Duty Administrative Review, and Partial Rescission; 2022–2023

AGENCY: Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) preliminarily finds that sales of certain steel nails (steel nails) from the United Arab Emirates (UAE) were not made at less than normal value (NV). The period of review (POR) is May 1, 2022, through April 30, 2023. Additionally, Commerce is rescinding this administrative review, in part, with respect to 19 companies because the requests for administrative review were timely withdrawn. We invite interested parties to comment on these preliminary results.

DATES: Applicable June 11, 2024.

FOR FURTHER INFORMATION CONTACT:

Robert Galantucci or Brittany Bauer, AD/CVD Operations, Office V, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482-2923 or (202) 482-3860, respectively.

SUPPLEMENTARY INFORMATION:

Background

On July 12, 2023, Commerce initiated an administrative review of the antidumping duty order on steel nails from the UAE,¹ in accordance with section 751(a) of the Tariff Act of 1930, as amended (the Act), with respect to 21 producers/exporters of the subject merchandise.² Commerce selected two mandatory respondents for individual examination: Master Nails and Pins Manufacturing, LLC (Master Nails)/ Middle East Manufacturing Steel LLC (MEM) (collectively, Master);³ and Rich Well Steel Industries LLC (Rich Well).⁴ On January 17, 2024, Commerce extended the deadline for the preliminary results of this administrative review until May 30, 2024.⁵

For details regarding the events that occurred subsequent to the initiation of the review, see the Preliminary Decision Memorandum.⁶ A list of topics included in the Preliminary Decision Memorandum is included as an appendix to this notice. The Preliminary 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 Preliminary Decision

¹ See *Certain Steel Nails from the United Arab Emirates: Amended Final Determination of Sales at Less Than Fair Value and Antidumping Duty Order*, 77 FR 27421 (May 10, 2012) (*Order*).

² See *Initiation of Antidumping and Countervailing Duty Administrative Reviews*, 88 FR 44262 (July 12, 2023).

³ Commerce previously determined that Master Nails and MEM comprise a single entity. See *Certain Steel Nails from the United Arab Emirates: Final Results of Antidumping Duty Administrative Review; 2020–2021*, 87 FR 61566 (October 12, 2022).

⁴ See Memorandum “Respondent Selection,” dated August 10, 2023.

⁵ See Memorandum, “Extension of Deadline for Preliminary Results of Antidumping Duty Administrative Review,” dated January 17, 2024.

⁶ See Memorandum, “Decision Memorandum for the Preliminary Results of the Administrative Review of the Antidumping Duty Order on Certain Steel Nails from the United Arab Emirates; 2022–2023,” dated concurrently with, and hereby adopted by, this notice (Preliminary Decision Memorandum).

Memorandum is available at <https://access.trade.gov/public/FRNoticesListLayout.aspx>.

Scope of the Order

The products covered by the *Order* are steel nails from the UAE. For a full description of the scope, see the Preliminary Decision Memorandum.

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 a party who requested the review withdraws the request within 90 days of the date of publication of the notice of initiation. Commerce received a timely-filed withdrawal request from Mid Continent Steel & Wire, Inc. (the petitioner) relating to 19 companies.⁷ Because the withdrawal request was timely filed, and no other party requested a review of these companies, in accordance with 19 CFR 351.213(d)(1), Commerce is rescinding this review with respect to the following companies: (1) Al Falaq Building Materials; (2) Al Khashab Building Materials Co., LLC.; (3) Al Rafaa Star Building Materials Est.; (4) Al Sabbah Trading and Importing, Est.; (5) Al-Khatib Est. (6) All Ferro Building Materials, LLC.; (7) Asgarali Yousuf Trading Co., LLC.; (8) Azymuth Consulting, LLC.; (9) Burj Al Tasmeem, Tr.; (10) Gheewala Hardware Trading Company, LLC; (11) Madar UAE; (12) Mustafa Building Materials Co. (LLC); (13) New World International, LLC.; (14) Okzeela Star Building Materials Trading, LLC.; (15) Rishi International, FZCO; (16) Samrat Wire Industry, LLC.; (17) Sea Lan Contracting; (18) SK Metal International DMCC.; and (19) Trade Circle Enterprises, LLC.

Methodology

Commerce is conducting this review in accordance with section 751(a) of the Act. We calculated export price in accordance with section 772(a) of the Act. We calculated NV in accordance with section 773 of the Act. For a full description of the methodology underlying these preliminary results, see the Preliminary Decision Memorandum.

Preliminary Results of Review

We preliminarily determine that the following weighted-average dumping margins exist for the period May 1, 2022, through April 30, 2023:

Exporter/producer	Weighted-average dumping margin (percent)
Master Nails and Pins Manufacturing, LLC/Middle East Manufacturing Steel, LLC	0.00
Rich Well Steel Industries LLC	0.00

Disclosure and Public Comment

We intend to disclose the calculations performed to parties within five days after public announcement of the preliminary results or, if there is no public announcement, within five days of the date of publication of this notice.⁸

Interested parties may submit case briefs no later than 30 days after the date of publication of this notice.⁹ Rebuttal briefs, limited to issues raised in the case briefs, may be filed not later than five days after the date for filing case briefs.¹⁰ Interested parties who submit case or rebuttal briefs in this proceeding must submit: (1) a table of contents listing each issue; and (2) a table of authorities.¹¹

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 brief 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.¹² 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).¹³

⁸ See 19 CFR 351.224(b).

⁹ See 19 CFR 351.309(c)(1)(ii); see also 19 CFR 351.303 (for general filing requirements).

¹⁰ 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*).

¹¹ See 19 CFR 351.309(c)(2) and (d)(2).

¹² We use the term “issue” here to describe an argument that Commerce would normally address in a comment of the Issues and Decision Memorandum.

¹³ See *APO and Service Final Rule*.

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.¹⁴ Requests should contain: (1) the party’s name, address, and telephone number; (2) the number of participants and whether any participant is a foreign national; and (3) a list of issues to be discussed. Issues raised in the hearing will be limited to those raised in case and rebuttal briefs.¹⁵ If a request for a hearing is made, Commerce intends to hold the hearing at a time and date to be determined. A hearing request must be filed electronically using ACCESS and received in its entirety by 5:00 p.m. Eastern Time within 30 days after the publication of this notice.

Assessment Rates

Upon completion of this administrative review, Commerce shall determine, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries covered by this review.¹⁶ Pursuant to 19 CFR 351.212(b)(1) if the weighted-average dumping margin for Master or Rich Well is not zero or *de minimis* (i.e., less than 0.5 percent) in the final results of this review, we will calculate importer-specific *ad valorem* antidumping duty assessment rates based on the ratio of the total amount of dumping calculated for the importer’s examined sales to the total entered value of those same sales. If either respondent’s weighted-average dumping margin is zero or *de minimis*, we intend to instruct CBP to liquidate the appropriate entries without regard to antidumping duties. The final results of this review shall be the basis for the assessment of antidumping duties on entries of merchandise covered by this review and for future deposits of estimated duties, where applicable.¹⁷

In accordance with Commerce’s “automatic assessment” practice, for entries of subject merchandise during the POR produced by Master or Rich Well for which the respondent did not know that the merchandise was destined for the United States, we will instruct CBP to liquidate those entries at the all-others rate established in the original less-than-fair-value (LTFV)¹⁸ if there is no rate for the intermediate

¹⁴ See 19 CFR 351.310(c).

¹⁵ See 19 CFR 351.310.

¹⁶ See 19 CFR 351.212(b)(1).

¹⁷ See section 751(a)(2)(C) of the Act.

¹⁸ See *Order*, 77 FR at 27422.

⁷ See Petitioner’s Letter, “Withdrawal of Request for Administrative Review,” dated October 10, 2023.

company(ies) involved in the transaction.¹⁹

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).

Cash Deposit Requirements

The following cash deposit requirements will be effective for all shipments of the 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 by section 751(a)(2)(C) of the Act: (1) the cash deposit rate for the companies listed above will be equal to the weighted-average dumping margin established in the final results of this administrative review, except if the rate is less than 0.50 percent and, therefore, *de minimis* within the meaning of 19 CFR 351.106(c)(1), in which case the cash deposit rate will be zero; (2) for merchandise exported by a company not covered in this review, but covered in a prior segment of the proceeding, the cash deposit rate will continue to be the company-specific rate published for the most recently-completed segment of this proceeding in which it was reviewed; (3) if the exporter is not a firm covered by this review, a prior review, or the original LTFV investigation, but the producer is, then the cash deposit rate will be the rate established for the most recently-completed segment of this proceeding for the producer of the merchandise; and (4) the cash deposit rate for all other producers or exporters will continue to be 4.30 percent,²⁰ the all-others rate established in the LTFV investigation. 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 the issues raised in any written briefs, not later than 120 days after the date of publication of this notice, 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 POR. Failure to comply with this requirement could result in Commerce's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of doubled antidumping duties.

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 and 19 CFR 351.221(b)(4).

Dated: May 30, 2024.

Abdelali Elouaradia,

Deputy Assistant Secretary for Enforcement and Compliance.

Appendix

List of Topics Discussed in the Preliminary Decision Memorandum

- I. Summary
- II. Background
- III. Scope of the *Order*
- IV. Partial Rescission of Administrative Review
- V. Discussion of the Methodology
- VI. Currency Conversion
- VII. Recommendation

[FR Doc. 2024-12740 Filed 6-10-24; 8:45 am]

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DEPARTMENT OF COMMERCE

International Trade Administration

[A-533-823]

Silicomanganese From India: Preliminary Results of Antidumping Duty Administrative Review and Intent To Rescind, in Part; 2022-2023

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) preliminarily determines that silicomanganese from India was sold in the United States at less than normal value during the period of review (POR) May 1, 2022, through April 30, 2023. Interested parties are invited to comment on these preliminary results.

DATES: Applicable June 11, 2024.

FOR FURTHER INFORMATION CONTACT: Mark Hoadley, 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) 482-3148.

SUPPLEMENTARY INFORMATION:

Background

On May 23, 2002, Commerce published the antidumping duty order on silicomanganese from India.¹ On May 19, 2023, Commerce received a timely request to conduct an administrative review of the *Order* from Maithan Alloys Limited (MAL),² and on May 31, 2023, Eramet Marietta, Inc. (the petitioner) requested a review of MAL and Rajadhiraj Tirupani Vinayak Natraj Pvt. Ltd. (RTVN).³ On July 12, 2023, in accordance with 19 CFR 351.221(c)(i), Commerce initiated an administrative review of MAL and RTVN.⁴ Pursuant to section 751(a)(3)(A) of the Tariff Act of 1930, as amended (the Act), on January 26, 2024, Commerce extended the deadline for the preliminary results of this review until May 23, 2024.⁵

For a detailed description of the events that followed the initiation of this review, see the Preliminary Decision Memorandum.⁶ A list of topics discussed in the Preliminary Decision Memorandum is attached as an appendix to this notice. The Preliminary Decision Memorandum is a public document and is available 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 Preliminary Decision Memorandum can be accessed directly at <https://access.trade.gov/public/FRNoticesListLayout.aspx>.

¹ See Notice of Amended Final Determination of Sales at Less than Fair Value and Antidumping Duty Orders: Silicomanganese from India, Kazakhstan, and Venezuela, 67 FR 36149 (May 23, 2002) (*Order*).

² See MAL's Letter, "Request for Administrative Review of Antidumping Order on behalf of Maithan Alloys Limited," dated May 19, 2023.

³ See Petitioner's Letter, "Request for Administrative Review of Antidumping Duty Order," dated May 31, 2023.

⁴ See *Initiation of Antidumping and Countervailing Duty Administrative Reviews*, 87 FR 42144 (July 14, 2022).

⁵ See Memorandum, "Extension of Deadline for Preliminary Results of Antidumping Duty Administrative Review," dated January 26, 2024.

⁶ See Memorandum, "Decision Memorandum for the Preliminary Results of the Antidumping Duty Administrative Review: Silicomanganese from India; 2022-2023," dated concurrently with, and hereby adopted by, this notice (Preliminary Decision Memorandum).

¹⁹ For a full discussion of this practice, see *Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties*, 68 FR 23954 (May 6, 2003).

²⁰ See *Order*, 77 FR at 27422.

Scope of the Order

The products covered by this *Order* are all forms, sizes and compositions of silicomanganese, except low-carbon silicomanganese. For a full description of the scope of the *Order*, see the Preliminary Decision Memorandum.

Intent To Rescind, in Part

As explained in the Preliminary Decision Memorandum, Commerce finds that RTVN had no suspended entries of subject merchandise and, therefore, pursuant to 19 CFR 351.213(d)(3), we intend to rescind the review with respect to RTVN.

Methodology

Commerce is conducting this review in accordance with sections 751(a)(1)(B) and (2) of the Act. For a full description of the methodology underlying these preliminary results, see the Preliminary Decision Memorandum.

Preliminary Results of the Review

We preliminarily determine the following estimated weighted-average dumping margin for the period May 1, 2022, through April 30, 2023:

Exporter or producer	Weighted-average dumping margin (percent)
Maithan Alloys Limited	1.71

Disclosure and Public Comment

Commerce intends to disclose its calculations performed to interested parties for these 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 this notice in the **Federal Register** in accordance with 19 CFR 351.224(b).

Case briefs or other written comments may be submitted to the Assistant Secretary for Enforcement and Compliance.⁷ Commerce will notify interested parties of the deadline for submission of case briefs. Rebuttal briefs, limited to issues raised in the case briefs, may be filed not later than five days after the date for filing case briefs.⁸ 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.⁹

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 brief 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.¹⁰ 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 determination in this investigation. 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).¹¹

Pursuant to 19 CFR 351.310(c), interested parties who wish to request a hearing, limited to issues raised in the case and rebuttal briefs, must submit a written request to the Assistant Secretary for Enforcement and Compliance, U.S. Department of Commerce, filed electronically, using ACCESS. Hearing requests should contain the party's name, address, and telephone number, the number of participants, and a list of the issues to be discussed. Issues raised in the hearing will be limited to those raised in the case and rebuttal briefs. An electronically filed request must be received successfully in its entirety by ACCESS by 5:00 p.m. Eastern Time, within 30 days of the publication date of this notice. If a request for a hearing is made, parties will be notified of the time and date of the hearing.¹²

Final Results of Review

Unless the deadline is extended pursuant to section 751(a)(3)(A) of the Act and 19 CFR 351.213(h)(2), Commerce intends to issue the final results of this administrative review, including the results of its analysis of the issues raised by the parties in any written briefs, no later than 120 days

after the date of publication of these preliminary results.

Assessment Rates

Pursuant to section 751(a)(2)(A) of the Act and 19 CFR 351.212(b)(1), Commerce will determine, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries of subject merchandise in accordance with the final results of this review. Commerce intends to issue assessment instructions to CBP no earlier than 35 days after the date of publication of the final results of this administrative 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).

If MAL's weighted-average dumping margin is not zero or *de minimis* (*i.e.*, less than 0.50 percent) in the final results of this review, Commerce intends to calculate importer-specific assessment rates on the basis of the ratio of the total amount of dumping calculated for each importer's examined sales to the total entered value of those sales. Where we do not have entered values for all U.S. sales to a particular importer, we will calculate an importer-specific, per-unit assessment rate on the basis of the ratio of the total amount of dumping calculated for the importer's examined sales to the total quantity of those sales.¹³ To determine whether an importer-specific, per-unit assessment rate is *de minimis*, in accordance with 19 CFR 351.106(c)(2), we also will calculate an importer-specific *ad valorem* ratio based on estimated entered values. If MAL's weighted-average dumping margin is zero or *de minimis* or where an importer-specific *ad valorem* assessment rate is zero or *de minimis*, we will instruct CBP to liquidate appropriate entries without regard to antidumping duties.¹⁴

In accordance with Commerce's "automatic assessment" practice, for entries of subject merchandise during the POR produced by MAL for which it did not know that the merchandise was destined for the United States, we intend to instruct CBP to liquidate those entries at the all-others rate in the original less-than-fair-value

⁷ See 19 CFR 351.309(c)(1)(ii); see also 19 CFR 351.303 for general filing requirements.

⁸ 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 Procedures*).

⁹ See 19 CFR 351.309(c)(2) and (d)(2).

¹⁰ We use the term "issue" here to describe an argument that Commerce would normally address in a comment of the Issues and Decision Memorandum.

¹¹ See *APO and Service Procedures*.

¹² See 19 CFR 351.310(d).

¹³ See 19 CFR 351.212(b)(1).

¹⁴ See 19 CFR 351.106(c)(2); see also *Antidumping Proceeding: Calculation of the Weighted-Average Dumping Margin and Assessment Rate in Certain Antidumping Proceedings; Final Modification*, 77 FR 8101, 8103 (February 14, 2012).

investigation (*i.e.*, 17.74 percent) if there is no rate for the intermediate company(ies) involved in the transaction.¹⁵

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 date of publication of the final results of this administrative review, as provided for by section 751(a)(2)(C) of the Act: (1) the company-specific cash deposit rate for MAL will be equal to the weighted-average dumping margin established in the final results of this review (except, if that rate is *de minimis* within the meaning of 19 CFR 351.106(c)(1), then the cash deposit rate will be zero); (2) for producers or exporters not covered in this review but covered in a prior segment of the proceeding, the cash deposit rate will continue to be the company-specific rate published for the most recently-completed segment of this proceeding in which they were reviewed; (3) if the exporter is not a firm covered in this review or a prior segment of the proceeding but the producer is, then the cash deposit rate will be the rate established for the most recently completed segment of this proceeding for the producer of the merchandise; and (4) the cash deposit rate for all other producers or exporters will continue to be 17.74 percent, the all-others rate established in the less-than-fair-value investigation.¹⁶ These cash deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice also serves as a preliminary reminder to importers of their responsibility under 19 CFR 351.402(f) 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

We are issuing and publishing these preliminary results in accordance with sections 751(a)(1) and 777(i) of the Act,

and 19 CFR 351.213(h)(2) and 351.221(b)(4).

Dated: May 23, 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 Preliminary Decision Memorandum

- I. Summary
- II. Background
- III. Scope of the Order
- IV. Intent to Rescind, In Part
- V. Affiliation and Collapsing
- VI. Discussion of the Methodology
- VII. Currency Conversion
- VIII. Recommendation

[FR Doc. 2024-12743 Filed 6-10-24; 8:45 am]

BILLING CODE 3510-DS-P

DEPARTMENT OF COMMERCE

International Trade Administration

[A-570-067]

Forged Steel Fittings From the People's Republic of China: Final Results of Antidumping Duty Administrative Review and Final Determination of No Shipments; 2021–2022

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) determines that Qingdao Bestflow Industrial Co., Ltd. (Bestflow), the sole participating mandatory respondent in this review and an exporter of forged steel fittings from the People's Republic of China (China), and Both-Well Taizhou Steel Fittings Co., Ltd. (Both-Well), a non-individually-examined exporter of forged steel fittings from China, sold subject merchandise in the United States at prices below normal value (NV) during the period of review (POR) November 1, 2021, through October 31, 2022. Further, Commerce determines that Xin Yi International Trade Co., Limited (Xin Yi) had no shipments of subject merchandise during the POR. Lastly, Commerce determines that 23 companies for which this review was initiated are not eligible for a separate rate and are, thus, part of the China-wide entity.

DATES: Applicable June 11, 2024.

FOR FURTHER INFORMATION CONTACT: Jinny Ahn, AD/CVD Operations, Office VI, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401

Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482-0968.

SUPPLEMENTARY INFORMATION:

Background

Commerce published the *Preliminary Results*¹ on December 7, 2023, and invited interested parties to comment. On March 22, 2024, we extended the deadline for the final results of this review until June 4, 2024.² For a complete description of the events that occurred since the *Preliminary Results*, see the Issues and Decision Memorandum.³

Scope of the Order⁴

The merchandise covered by the *Order* is forged steel fittings from China. Subject carbon and alloy forged steel fittings are normally entered under Harmonized Tariff Schedule of the United States (HTSUS) subheadings 7307.99.1000, 7307.99.3000, 7307.99.5045, and 7307.99.5060. They also may be entered under HTSUS subheadings 7307.92.3010, 7307.92.3030, 7307.92.9000, and 7326.19.0010. The HTSUS subheadings are provided for convenience and customs purposes; the written description of the scope is dispositive. For a complete description of the scope of the *Order*, see the Issues and Decision Memorandum.

Analysis of Comments Received

All issues raised in the parties' briefs are addressed in the Issues and Decision Memorandum. A list of the issues addressed is included as Appendix I 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

¹ See *Forged Steel Fittings from the People's Republic of China: Preliminary Results of Antidumping Duty Administrative Review, Preliminary Determination of No Shipments; 2021–2022*, 88 FR 85221 (December 7, 2023) (*Preliminary Results*), and accompanying Preliminary Decision Memorandum (PDM).

² See Memorandum, "Extension of Deadline for Final Results of Antidumping Duty Administrative Review," dated March 22, 2024.

³ See Memorandum, "Decision Memorandum for the Final Results of the Administrative Review of the Antidumping Duty Order on Forged Steel Fittings from the People's Republic of China; 2021–2022," dated concurrently with, and hereby adopted by, this notice (Issues and Decision Memorandum).

⁴ See *Forged Steel Fittings from Italy and the People's Republic of China: Antidumping Duty Orders*, 83 FR 60397, dated November 26, 2018 (*Order*).

¹⁵ For a full discussion of this practice, see *Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties*, 68 FR 23954 (May 6, 2003).

¹⁶ See *Order*, 86 FR at 7530.

directly at <https://access.trade.gov/public/FRNoticesListLayout.aspx>.

Changes Since the Preliminary Results

Based on our review of the record and comments received from interested parties regarding the *Preliminary Results*, we made certain revisions to the margin calculations for Bestflow.⁵ Further, we have assigned Bestflow's revised final weighted-average dumping margin to the non-examined separate rate respondent, Both-Well. For a discussion of these changes, see the Issues and Decision Memorandum.

Final Determination of No Shipments

In the *Preliminary Results*, we preliminarily determined that Xin Yi had no shipments of subject merchandise to the United States during the POR.⁶ No party filed comments with respect to this preliminary determination and we received no information to contradict the preliminary finding. Therefore, we continue to find that Xin Yi had no shipments of subject merchandise during the POR and will issue appropriate liquidation instructions that are consistent with our "automatic assessment" clarification for these final results.⁷

Separate Rate

In our *Preliminary Results*, we determined that Bestflow and Both-Well demonstrated their eligibility for separate rates.⁸ We received no arguments since the issuance of the *Preliminary Results* that provide a basis for reconsideration of these determinations. Therefore, for these final results, we continue to find that the two companies listed in the table in the "Final Results of Review" section of this notice are each eligible for a separate rate.

The China-Wide Entity

In the *Preliminary Results*, Commerce found that 23 companies for which a review was initiated did not establish their eligibility for a separate rate.⁹ No parties contested this finding. As such, we continue to determine these 23 companies identified in Appendix II are part of the China-wide entity. Because no party requested a review of the China-wide entity, and Commerce no

longer considers the China-wide entity as an exporter conditionally subject to administrative reviews,¹⁰ we did not conduct a review of the China-wide entity. Thus, the weighted-average dumping margin for the China-wide entity rate (*i.e.*, 142.72 percent) is not subject to change.¹¹

Rate for Non-Examined Separate Rate Respondent

The statute and Commerce's regulations do not address what weighted-average dumping margin to apply to companies not selected for individual examination when Commerce limits its examination in an administrative review pursuant to section 777A(c)(2) of the Tariff Act of 1930, as amended (the Act). Generally, Commerce looks to section 735(c)(5) of the Act, which provides instructions for calculating the all-others rate in an investigation, for guidance when calculating the weighted-average dumping margin for respondents that are not individually examined in an administrative review. Section 735(c)(5)(A) of the Act states that the all-others rate should be calculated by averaging the weighted-average dumping margins determined for individually-examined respondents, excluding rates that are zero, *de minimis*, or based entirely on facts available.

In the *Preliminary Results*,¹² and consistent with Commerce's practice,¹³ we assigned the non-examined, separate rate company (*i.e.*, Both-Well) a weighted-average dumping margin equal to the calculated weighted-average dumping margin for the mandatory respondent whose rate was not zero, *de minimis* (*i.e.*, less than 0.5 percent), or based entirely on facts available (*i.e.*, the weighted-average dumping margin for Bestflow). Both-Well and the Bonney Forge Corporation, a domestic interested party, commented on the methodology for calculating this separate rate. See Issues and Decision Memorandum at Comment 5. For the final results, we continue to apply this approach and assign Both-Well the weighted-average dumping margin calculated for Bestflow which is not zero, *de minimis*, or based entirely on facts available, as it is

consistent with the intent of, and our use of, section 735(c)(5)(A) of the Act.¹⁴

Final Results of Review

Commerce determines that the following weighted-average dumping margins exist for the period November 1, 2021, through October 31, 2022:

Exporter	Weighted-average dumping margin (percent)
Qingdao Bestflow Industrial Co., Ltd	118.97
Review-Specific Rate Applicable to the Following Company	
Both-Well (Taizhou) Steel Fittings Co., Ltd	118.97

Disclosure

We intend to disclose the calculations performed in connection with these final results to interested parties in this review under an administrative protective order (APO) within five days of the date of publication of this notice in the **Federal Register** in accordance with 19 CFR 351.224(b).

Assessment Rates

Pursuant to section 751(a)(2)(C) of the Act and 19 CFR 351.212(b), Commerce has determined, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries covered by this review. 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).

We will instruct CBP to assess antidumping duties on all appropriate entries covered by this review, when the company-specific weighted-average dumping margin is not zero or *de minimis* (*i.e.*, less than 0.50 percent), or when the importer-specific assessment rate calculated in the final results of this review is not zero or *de minimis*.¹⁵ Where either a company's weighted-average dumping margin is zero or *de*

⁵ See Memorandum, "Final Results Calculation Memorandum for Both-Well," dated concurrently with this notice.

⁶ See *Preliminary Results*, 88 FR at 85222.

⁷ See *Non-Market Economy Antidumping Proceedings: Assessment of Antidumping Duties*, 76 FR 65694 (October 24, 2011) (*Assessment Practice Refinement*).

⁸ See *Preliminary Results* PDM at 7–8.

⁹ *Id.* at 9.

¹⁰ 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, 65969–70 (November 4, 2013).

¹¹ See *Order*, 83 FR at 60397.

¹² See *Preliminary Results* PDM at 9.

¹³ See, e.g., *Certain Kitchen Appliance Shelving and Racks from the People's Republic of China: Final Determination of Sales at Less Than Fair Value*, 74 FR 36656, 36660 (July 24, 2009).

¹⁴ See *Certain Frozen Warmwater Shrimp from the Socialist Republic of Vietnam: Final Results and Final Partial Rescission of Antidumping Duty Administrative Review*, 76 FR 56158, 56160 (September 12, 2011).

¹⁵ See 19 CFR 351.106(c)(2).

minimis, or an importer-specific assessment rate is zero or *de minimis*, we will instruct CBP to liquidate the appropriate entries without regard to antidumping duties.

For Bestflow, which has a final weighted-average dumping margin that is not zero or *de minimis* (*i.e.*, less than 0.5 percent), we will instruct CBP to assess antidumping duties at the time of liquidation, in accordance with 19 CFR 351.212(b)(1).¹⁶ Because Bestflow did not report entered value for its U.S. sales, we intend to calculate importer- or customer-specific per-unit assessment rates by dividing the total amount of dumping calculated for all reviewed sales to the importer or customer by the total quantity of the same sales. Commerce will also calculate (estimated) *ad valorem* importer- or customer-specific assessment rates with which to assess whether the per-unit assessment rates are *de minimis*. We intend to calculate estimated importer- (or customer-specific *ad valorem* assessment rates by dividing the total amount of dumping calculated for all reviewed U.S. sales to the importer or customer by the total estimated entered value of the same sales.¹⁷

For the respondent that was not selected for individual examination in this administrative review, and which qualified for a separate rate (*i.e.*, Both-Well), the assessment rate will be equal to the weighted-average dumping margin from the final results (*i.e.*, 118.97 percent). For the companies who are not eligible for a separate rate, and, thus, are part of the China-wide entity, we will instruct CBP to apply an *ad valorem* assessment rate of 142.72 percent to all POR entries of subject merchandise which was exported by those companies.

Pursuant to a refinement in our non-market economy practice, for sales that were not reported in the U.S. sales data submitted by Bestflow during this review, we will instruct CBP to liquidate entries associated with those sales at the rate for the China-wide entity.¹⁸ Additionally, any suspended entries that entered under Xin Yi's case number (*i.e.*, at Xin Yi's cash deposit rate) will be liquidated at the

antidumping duty assessment rate for the China-wide entity.¹⁹

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 section 751(a)(2)(C) of the Act: (1) for companies listed in the table above, the cash deposit rate will be 118.97 percent; (2) for previously examined Chinese and non-Chinese exporters not listed above that have separate rates, the cash deposit rate will continue to be the exporter's existing cash deposit rate; (3) 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 (*i.e.*, 142.72 percent); and (4) for all non-Chinese exporters of subject merchandise which have not received their own separate 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.

Notification to Importers

This notice also 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 and/or countervailing duties prior to liquidation of the relevant entries during this POR. Failure to comply with this requirement could result in Commerce's presumption that reimbursement of antidumping and/or countervailing duties occurred and the subsequent assessment of double antidumping duties, and/or an increase in the amount of antidumping duties by the amount of the countervailing duties.

Administrative Protective Order

This notice also serves as a reminder to parties subject to an APO of their responsibility concerning the return or destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3), which continues to govern business proprietary information in this segment of the proceeding. 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 violation subject to sanction.

Notification to Interested Parties

These final results and notice are issued and published in accordance with sections 751(a)(1) and 777(i)(1) of the Act, and 19 CFR 351.213(h) and 19 CFR 351.221(b)(5).

Dated: June 4, 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 I

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 Used the Latest Revised U.S. Sales Database for the Calculation of Bestflow's Weighted-Average Dumping Margin
 - Comment 2: Inland Freight Surrogate Value (SV)
 - Comment 3: Calculation of Labor SV Covering Multiple Years of the POR
 - Comment 4: Whether to Continue to Apply Partial Adverse Facts Available (AFA) to Determine the Normal Value (NV) for the Sales of Merchandise Supplied by Bestflow's Uncooperative Suppliers
 - Comment 5: Whether to Continue to Assign Bestflow's Weighted-Average Dumping Margin to Both-Well
- VI. Recommendation

Appendix II

Companies Not Eligible for a Separate Rate and Treated as Part of the China-Wide Entity

1. Cixi Baicheng Hardware Tools, Ltd.
2. Dalian Guangming Pipe Fittings Co., Ltd.
3. Eaton Hydraulics (Luzhou) Co., Ltd.
4. Eaton Hydraulics (Ningbo) Co., Ltd.
5. Jiangsu Forged Pipe Fittings Co., Ltd.
6. Jiangsu Haida Pipe Fittings Group Co.
7. Jinan Mech Piping Technology Co., Ltd.
8. Jining Dingguan Precision Parts Manufacturing Co., Ltd.
9. Lianfa Stainless Steel Pipes & Valves (Qingyun) Co., Ltd.
10. Luzhou City Chengrun Mechanics Co., Ltd.
11. Ningbo HongTe Industrial Co., Ltd.
12. Ningbo Long Teng Metal Manufacturing Co., Ltd.
13. Ningbo Save Technology Co., Ltd.
14. Ningbo Zhongan Forging Co., Ltd.
15. Q.C. Witness International Co., Ltd.
16. Shanghai Lon Au Stainless Steel Materials Co., Ltd.
17. Witness International Co., Ltd.
18. Yancheng Boyue Tube Co., Ltd.
19. Yancheng Haohui Pipe Fittings Co., Ltd.
20. Yancheng Jiuwei Pipe Fittings Co., Ltd.
21. Yancheng Manda Pipe Industry Co., Ltd.
22. Yingkou Guangming Pipeline Industry Co., Ltd.

¹⁶ Commerce will apply the assessment rate calculation method adopted in *Antidumping Proceedings: Calculation of the Weighted-Average Dumping Margin and Assessment Rate in Certain Antidumping Proceedings: Final Modification*, 77 FR 8101 (February 14, 2012).

¹⁷ See 19 CFR 351.212 (b)(1).

¹⁸ See *Assessment Practice Refinement*, 76 FR at 65694 for a full discussion of this practice.

¹⁹ *Id.*

23. Yuyao Wanlei Pipe Fitting Manufacturing Co., Ltd.

[FR Doc. 2024–12738 Filed 6–10–24; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

Agency Information Collection Activities; Submission to the Office of Management and Budget (OMB) for Review and Approval; Comment Request; Application for Export Trade Certificate of Review

AGENCY: International Trade Administration, Department of 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 August 12, 2024.

ADDRESSES: Interested persons are invited to submit written comments by mail to Amanda Reynolds, Team Lead, International Trade Administration (ITA) by email to ETCA@trade.gov or PRA@trade.gov. Please reference OMB Control Number 0625–0125 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 Amanda Reynolds, Team Lead, (202) 482–5131 and email ETCA@trade.gov.

SUPPLEMENTARY INFORMATION:

I. Abstract

Title III of the Export Trading Company Act (hereinafter “the Act”) of 1982 (Pub. L. 97–290, 15 U.S.C. 4001 *et seq.*), authorizes the Secretary of Commerce to issue, with the concurrence of the Attorney General, an Export Trade Certificate of Review to any person that establishes that its proposed export trade, export trade

activities, and methods of operation meet the four standards found in section 303 (a) of the Act, 15 U.S.C. 4001 *et seq.* An Export Trade Certificate of Review provides the certificate holder and its members with limited antitrust immunity for specified export-related activities. Application for an Export Trade Certificate of Review is voluntary. The information to be collected is found at 15 CFR part 325.3—Export Trade Certificates of Review. The collection of information is necessary for both the Departments of Commerce and Justice to conduct an analysis, in order to determine whether the applicant and its members are eligible to receive the protection of an Export Trade Certificate of Review and whether the applicant's proposed export-related conduct meets the standards in Section 303(a) of the Act. The collection of information constitutes the essential basis of the statutory determinations to be made by the Secretary of Commerce and the Attorney General.

The Department of Commerce conducts its economic and legal analysis of the information supplied by applicants through the Office of Trade and Economic Analysis and the Office of the General Counsel. In the Department of Justice, analysis is conducted by the Antitrust Division.

Title III was enacted to reduce uncertainty regarding the application of U.S. antitrust laws to export activities. An Export Trade Certificate of Review provides its holder and members named in the Certificate with (a) protection from government actions under state and federal antitrust laws for the export conduct specified in the Certificate, and (b) certain protection from private suits, by limiting liability in private actions to actual damages when the challenged activities are covered by an Export Trade Certificate of Review.

II. Method of Collection

The form is sent by request to U.S. firms.

III. Data

OMB Control Number: 0625–0125.
Form Number(s): ITA–4093P.

Type of Review: Regular submission, extension of a current information collection.

Affected Public: Business or other for-profit organizations; not-for-profit institutions, and state, local or tribal government.

Estimated Number of Respondents: 9.

Estimated Time per Response: 32 hours (application); 2 hours (annual report).

Estimated Total Annual Burden Hours: 426 hours.

Estimated Total Annual Cost to Public: \$0.

Respondent's Obligation: Voluntary.

Legal Authority: Title III of the Export Trading Company Act of 1982, 15 U.S.C. 4011–4021.

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. 2024–12771 Filed 6–10–24; 8:45 am]

BILLING CODE 3510–DR–P

DEPARTMENT OF COMMERCE

National Institute of Standards and Technology

Agency Information Collection Activities; Submission to the Office of Management and Budget (OMB) for Review and Approval; Comment Request; Generic Clearance for Decision Science Data Collections

AGENCY: National Institute of Standards and Technology (NIST), 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 August 12, 2024.

ADDRESSES: Interested persons are invited to submit written comments by mail to Maureen O'Reilly, Management Analyst, NIST at PRANIST@nist.gov. Please reference OMB Control Number 0693-0089 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 Maureen O'Reilly, Management Analyst, NIST, 100 Bureau Drive, Gaithersburg, MD 20899, 301-975-3189 or maureen.oreilly@nist.gov.

SUPPLEMENTARY INFORMATION:

I. Abstract

The core mission of the National Institute of Standards and Technology (NIST) is to promote U.S. innovation and industrial competitiveness by advancing measurement science, standards, and technology in ways that enhance economic security and improve our quality of life. NIST's operating units across the agency increasingly recognize that the built environment is meant to serve social and economic functions. With this in mind, NIST proposes to conduct a number of data collection efforts directly related to decision-making across individuals, institutions, and communities relevant to key research areas of the agency. The use of decision and information science is critical to further the mission of NIST to promote U.S. innovation and industrial competitiveness. NIST proposes to conduct a number of data collection efforts in decision and information science to include: decision analysis, risk analysis, cost-benefit and cost-effectiveness analysis, constrained optimization, simulation modeling, and application of perception, information processing, and decision models and theories; and drawing on parts of operations research, microeconomics,

statistical inference, management control, cognitive and social psychology, and computer science. By focusing on decisions as the unit of analysis, decision science provides a unique framework for understanding interactions across technologies, socio-economic networks, organizations (e.g., institutions, firms), elements of the built environment, and a range of ecological problems and perceptions that influence these decisions.

Data may be collected through a variety of modes, including but not limited to electronic or social media, direct or indirect observation (i.e., in-person, video and audio collections), interviews, structured questionnaires, and focus groups.

II. Method of Collection

NIST will collect this information by electronic means, when possible, as well as by mail, fax, telephone, technical discussions, and in-person interviews. NIST may also utilize observational techniques to collect this information.

Furthermore, remuneration will be offered to respondents when deemed appropriate. Remuneration is justified due to:

(1) The complex study design of many collections requires ongoing participation of various respondents, each of whom is important to achieving study goals. In such studies, should attrition occur at a higher rate than expected, the study goals will not be met.

(2) There is burden on the respondent to take time out of their workday in many cases. There will be equity in the use of remuneration: all respondents will be treated equally with regard to incentives.

III. Data

OMB Control Number: 0693-0089.

Form Number(s): None.

Type of Review: Regular submission, extension of a current information collection.

Affected Public: Individuals or households; first responders; businesses or other for-profit organizations; not-for-profit institutions; State, local or tribal government; Federal government; Standards-making bodies; Universities.

Estimated Number of Respondents: 30,000.

Estimated Time per Response: Varied, dependent upon the data collection method used. The possible response time may be 15 minutes to complete a questionnaire or 2 hours to participate in an interview.

Estimated Total Annual Burden Hours: 15,000.

Estimated Total Annual Cost to Public: \$125,000.

Respondent's Obligation: Voluntary.
Legal Authority:

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. 2024-12768 Filed 6-10-24; 8:45 am]

BILLING CODE 3510-13-P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648-XE029]

Marine Mammals and Endangered Species

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Notice; issuance of permits.

SUMMARY: Notice is hereby given that permits have been issued to the following entities under the Marine Mammal Protection Act (MMPA) and

the Endangered Species Act (ESA), as applicable.

ADDRESSES: The permits and related documents are available for review upon written request via email to NMFS.Pr1Comments@noaa.gov.

FOR FURTHER INFORMATION CONTACT: Shasta McClenahan, Ph.D. (Permit No. 27342) and Malcolm Mohead (Permit No. 27830); at (301) 427–8401.

SUPPLEMENTARY INFORMATION: Notices were published in the **Federal Register** on the dates listed below that requests for a permit or permit amendment had

been submitted by the below-named applicants. To locate the **Federal Register** notice that announced our receipt of the application and a complete description of the activities, go to <https://www.federalregister.gov> and search on the permit number provided in table 1 below.

TABLE 1—ISSUED PERMITS

Permit No.	RTID	Applicant	Previous Federal Register notice	Issuance date
27342	0648–XD819	Heidi Pearson, Ph.D., University of Alaska Southeast, 11066 Auke Lake Way, Juneau, AK 99801.	89 FR 20182, March 21, 2024	May 7, 2024.
27830	0648–XD822	Gregory Lewbart, V.M.D., North Carolina State University, 1060 William Moore Drive, Raleigh, NC 27607.	89 FR 22683, April 2, 2024	May 13, 2024.

In compliance with the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*), a final determination has been made that the activities proposed are categorically excluded from the requirement to prepare an environmental assessment or environmental impact statement.

As required by the ESA, as applicable, issuance of these permits was based on a finding that such permits: (1) were applied for in good faith; (2) will not operate to the disadvantage of such endangered species; and (3) are consistent with the purposes and policies set forth in section 2 of the ESA.

Authority: The requested permits have been issued under the MMPA of 1972, as amended (16 U.S.C. 1361 *et seq.*), the regulations governing the taking and importing of marine mammals (50 CFR part 216), the ESA of 1973, as amended (16 U.S.C. 1531 *et seq.*), and the regulations governing the taking, importing, and exporting of endangered and threatened species (50 CFR parts 222–226), as applicable.

Dated: June 5, 2024.

Julia M. Harrison,
Chief, Permits and Conservation Division,
Office of Protected Resources, National
Marine Fisheries Service.

[FR Doc. 2024–12707 Filed 6–10–24; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Sanctuary System Business Advisory Council: Public Meeting

AGENCY: Office of National Marine Sanctuaries (ONMS), National Ocean Service, National Oceanic and

Atmospheric Administration,
Department of Commerce.

ACTION: Notice of open public meeting.

SUMMARY: Notice is hereby given of a meeting of the Sanctuary System Business Advisory Council (council). The meeting is open to the public, and an opportunity for oral and written comments will be provided.

DATES: The meeting will be held on Wednesday, June 26, 2024 from 12 p.m. to 1 p.m. eastern time (ET), and an opportunity for public comment will be provided around 12:50 p.m. ET. Both times and agenda topics are subject to change.

ADDRESSES: The meeting will be held virtually using Google Meet. To participate, please use the weblink provided below. If you are unable to participate online, you can also connect to the public meeting using the phone number provided.

- **Weblink:** meet.google.com/cio-obgn-ye
- **Phone:** (US) +1 352–612–1066 PIN: 470 410 197#

To provide an oral public comment during the virtual meeting, please sign up prior to or during the meeting by contacting Sage Riddick by phone (240–560–3365) or email (sage.riddick@noaa.gov). To provide written public comment, please send the comment to Sage Riddick prior to or during the meeting via email (sage.riddick@noaa.gov). Please note, the meeting will not be recorded. However, public comments, including any associated names, will be captured in the minutes of the meeting, will be maintained by ONMS as part of its administrative record, and may be subject to release pursuant to the Freedom of Information Act. The entirety of the comment, including the name of the commenter,

email address, attachments, and other supporting materials, will be publicly accessible. Sensitive personally identifiable information, such as account numbers and Social Security numbers, should not be included with the comment. By signing up to provide a public comment, you agree that these communications, including your name and comment, will be maintained as described here.

FOR FURTHER INFORMATION CONTACT: Sage Riddick, Office of National Marine Sanctuaries, 1305 East West Highway, Silver Spring, Maryland 20910 (Phone: 240–560–3365; Email: sage.riddick@noaa.gov).

SUPPLEMENTARY INFORMATION: ONMS serves as the trustee for a network of underwater parks encompassing more than 620,000 square miles of marine and Great Lakes waters from Washington State to the Florida Keys, and from Lake Huron to American Samoa. The network includes a system of 15 national marine sanctuaries and Papahānaumokuākea and Rose Atoll marine national monuments. National marine sanctuaries protect our Nation's most vital coastal and marine natural and cultural resources, and through active research, management, and public engagement, sustain healthy environments that are the foundation for thriving communities and stable economies.

One of the many ways ONMS ensures public participation in the designation and management of national marine sanctuaries is through the formation of advisory councils. The Sanctuary System Business Advisory Council (council) provides advice and recommendations to the ONMS Director regarding the relationship of ONMS with the business community. Additional information on this council

can be found at <https://sanctuaries.noaa.gov/management/bac/>.

Matters to be discussed: The meeting will include updates from Capitol Hill Ocean Week, member updates, and voting on amendments to the council's charter. For a complete agenda, including times and topics, please visit <http://sanctuaries.noaa.gov/management/bac/meetings.html>.

Authority: 16 U.S.C. 1431, *et seq.*

John Armor,

Director, Office of National Marine Sanctuaries, National Ocean Service, National Oceanic and Atmospheric Administration.

[FR Doc. 2024-12699 Filed 6-10-24; 8:45 am]

BILLING CODE 3510-22-P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

Notice of Availability of Draft Guidance on Designation of New Regional Ocean Partnerships

AGENCY: Office for Coastal Management, National Ocean Service, National Oceanic and Atmospheric Administration, U.S. Department of Commerce.

ACTION: Notice of availability of draft guidance regarding the designation of new regional ocean partnerships; request for comments.

SUMMARY: Under the James M. Inhofe National Defense Authorization Act for Fiscal Year 2023 (NDAA), Coastal States (including Puerto Rico, the United States Virgin Islands, Guam, the Commonwealth of the Northern Mariana Islands, the Trust Territories of the Pacific Islands, and American Samoa), federally-recognized Indian Tribes (including Alaska native villages), and other entities may form new partnerships and apply to the National Oceanic and Atmospheric Administration (NOAA) (as delegated) for designation as a regional ocean partnership. Regional ocean partnerships coordinate the management of ocean, coastal, and Great Lakes resources. NOAA invites public comment on draft guidance on designating new regional ocean partnerships under the NDAA.

DATES: Comments are due by July 11, 2024.

ADDRESSES: Copies of the draft designation guidance document may be found on www.regulations.gov (search for NOAA-NOS-2024-0066) and NOAA's Office for Coastal Management website at <https://coast.noaa.gov/data/>

coasthome/funding/_pdf/bil-rop-designation-guidance.pdf. Comments may be submitted by:

- **Electronic Submission:** Submit all electronic public comments via the Federal eRulemaking Portal. Go to www.regulations.gov and enter NOAA-NOS-2024-0066 in the search box, then click the "comment" icon, complete the required fields, and enter or attach your comments.

- **Mail:** Submit written comments to Joshua Lott, Office for Coastal Management, NOS, NOAA, 1305 East-West Highway, Silver Spring, Maryland 20910; ATTN: Regional Ocean Partnership Designation Guidance.

Instructions: All comments received are a part of the public record and generally will be posted for public viewing on www.regulations.gov without change. All personally identifiable information (name, address, etc.), confidential business information, or otherwise sensitive information submitted voluntarily by the commenter will be publicly accessible. The Federal agencies will accept anonymous comments (enter "N/A" in the required fields you wish to remain anonymous). 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 Federal agencies 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). Comments that are not responsive or contain profanity, vulgarity, threats, or other inappropriate language will not be considered.

FOR FURTHER INFORMATION CONTACT:

Joshua Lott, Office for Coastal Management, NOS, NOAA, 1305 East-West Highway, Silver Spring, Maryland 20910; ATTN: Regional Ocean Partnership Designation Guidance. Phone: (202) 670-3826; or Email: rop.iija@noaa.gov.

SUPPLEMENTARY INFORMATION: Regional ocean partnerships are regional organizations, voluntarily convened by coastal States and Indian Tribes and designated by NOAA (as delegated, per the NDAA) to coordinate the management of ocean, coastal, and Great Lakes resources. These partnerships work in collaboration with other governments (including Tribal, Federal, and local) and stakeholders to address ocean and coastal issues of common concern in that region.

There are four existing regional ocean partnerships: the Gulf of Mexico Alliance, the Northeast Regional Ocean

Council, the Mid-Atlantic Regional Council on the Ocean, and the West Coast Ocean Alliance. Section 10102(b)(3) of the NDAA, codified at 16 U.S.C. 1468(b)(3), designates these four entities as regional ocean partnerships; as such, this draft designation guidance and application process for new partnerships does not apply to them.

This draft designation guidance has been developed to address the membership, organization, and required elements of new partnerships. NOAA proposes to include the following information in the guidance: introduction and background; instructions on submitting a new partnership application to NOAA; requirements for new regional ocean partnerships; and eligibility for funding as a partnership. Applications to NOAA for new regional ocean partnerships must identify: the members of the new partnership, the governing body of the new partnership, and the purposes and functions of the new partnership.

The draft designation guidance document may be found on www.regulations.gov (search for NOAA-NOS-2024-0066) and NOAA's Office for Coastal Management website at https://coast.noaa.gov/data/coasthome/funding/_pdf/bil-rop-designation-guidance.pdf.

Authority: 16 U.S.C. 1468

Jeffrey L. Payne,

Director, Office for Coastal Management, National Ocean Service, National Oceanic and Atmospheric Administration.

[FR Doc. 2024-12670 Filed 6-10-24; 8:45 am]

BILLING CODE 3510-08-P

DEPARTMENT OF DEFENSE

Office of the Secretary

Listening Sessions on Draft Environmental Justice Strategy Approach

AGENCY: Office of the Undersecretary of Defense for Acquisition and Sustainment, Department of Defense (DoD).

ACTION: Notice; listening sessions and notice of availability.

SUMMARY: Pursuant to an Executive order (E.O.), the DoD is updating its EJ Strategy. DoD is soliciting feedback on its draft goals and overall approach to addressing EJ. This draft information is included in the **SUPPLEMENTARY INFORMATION** section.

DATES: Interested individuals are invited to provide verbal and written feedback on DoD's draft goals and overall

approach to addressing EJ throughout the Department.

DoD is offering the following two public, virtual listening sessions:

Tuesday, June 25, 2024 10:00 a.m.–12:00 p.m. Eastern Standard Time (EST), Virtual, Registration link: <https://bahmeet.webex.com/weblink/register/r2f51bca3daf05861f65172223990d09>

Thursday, June 27, 2024 4:00 p.m.–6:00 p.m. EST Virtual, Registration link: <https://bahmeet.webex.com/weblink/register/r14abbe7c9b79eed68e43d6baa288ab07>

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.

DoD will consider all comments received during the public listening sessions. Please clarify whether feedback is intended for the Department's draft EJ goals or overall approach to addressing EJ. DoD also plans to record these listening sessions to accurately capture inputs on the draft EJ goals and implementation approach. DoD plans to only use the recordings for this purpose. All feedback, including personal information, provided during the listening sessions may be made public. The Department cautions commenters from including personal or other identifying information they do not want made publicly available when submitting their feedback.

ADDRESSES: Individuals may also provide written feedback. DoD will consider all comments postmarked by 07/09/2024. Please clarify whether feedback is intended for the Department's draft EJ goals or overall approach to addressing EJ.

Submitting Comments: Individuals may submit written comments via one of the following methods:

- Email to: terry.l.bowers14.civ@mail.mil; osd.ejstrategy@mail.mil or
- Mail hard copy to: Terry Bowers, Office of the Assistant Secretary of Defense for Energy, Installations, and Environment, 3400 Defense Pentagon, Washington, DC 20301–3400.

Written comments must include the commenter's name and reference the Department's EJ Strategy. All feedback, including personal information, provided via written comment may be made public. The Department cautions commenters from including personal or other identifying information they do not want made publicly available when submitting their feedback.

Accessing Documents and Additional Information: Individuals may access additional information on the

Department's EJ efforts through the following link: <https://www.denix.osd.mil/ej/>.

FOR FURTHER INFORMATION CONTACT: Mr. Terry Bowers, 571–232–2482, terry.l.bowers14.civ@mail.mil and osd.ejstrategy@mail.mil.

SUPPLEMENTARY INFORMATION:

Background: E.O. 14096 directs Federal agencies to develop an EJ Strategy that will “set forth the agency's vision, goals, priority actions, and metrics to address and advance environmental justice and to fulfill the directives of the E.O., including through the identification of new staffing, policies, regulations, or guidance documents”, as well as “identify and address opportunities through regulations, policies, permits, or other means to improve accountability and compliance with any statute the agency administers that affects the health and environment of communities with environmental justice concerns.”

To advance its EJ efforts, the Department is updating its EJ Strategy in accordance with E.O. 14096. DoD will evaluate all verbal and written feedback received on the draft goals and overall approach to advancing EJ across the Department.

Listening Session Format: The listening sessions listed above will be two hours. Each session will start with an overview and then participants will have an opportunity to provide feedback through a variety of engagement tools. If you require a reasonable accommodation to attend one of the listening sessions, please email: terry.l.bowers14.civ@mail.mil, orosd.ejstrategy@mail.mil.

Draft Goals and Overall Approach to Addressing EJ: DoD would appreciate feedback on the following questions:

1. Do the drafted EJ goals and overall implementation approach address your concerns regarding the advancement of EJ throughout the Department? Why or why not? Note: the drafted items are included below.
2. Are there any concerns with the Department's drafted overall approach to addressing EJ?
3. Are there any concerns not currently reflected in the drafted materials included below?

DoD drafted the following Goals in response to E.O. 14096:

- Regularly assess EJ-related plans, policies, programs, and actions across all DoD programs after first educating and expanding EJ awareness of actions disproportionately impacting low income, minority, Tribal, disabled, and/or descendant populations across all DoD programs.

- Identify, characterize, and assess effects of DoD plans, programs, policies, and activities disproportionately impacting communities and stakeholders, including whether effects are chronic or acute.

- Investigate methods to mitigate impacts of DoD plans, programs, policies, and activities after first identifying potentially affected communities and stakeholders.

- Provide tools to improve DoD's capacity to conduct meaningful and effective work supporting EJ.
- Strengthen outreach to communities and stakeholders that may be disproportionately affected by high and adverse environmental, human health, or cultural impacts from DoD programs, policies, and activities through appropriate public engagement.

DoD also drafted the following overall approach to addressing EJ:

DoD anticipates that it will need to execute a considerable amount of work to effectively integrate EJ across the enterprise to meet E.O. 14096. Historically, DoD has used compliance with the National Environmental Policy Act, National Historic Preservation Act, and Comprehensive Environmental Response, Compensation, and Liability Act processes to address EJ. The Department may take a more proactive approach by incorporating EJ into Office of the Secretary of Defense (OSD), Military Department (MILDEP), and installation-level planning processes. These plans may include or discuss installation master planning, climate change, cultural and natural resources conservation, integrated installation resilience, and others. Integrating EJ into the Department's policies and programs will require consistent coordination across OSD, the MILDEPs, individual installations, and other DoD equities.

The Department may investigate methods to streamline EJ implementation, including:

- Issuing a Secretary of Defense or Deputy Secretary of Defense message, discussing the importance of EJ and explaining CEQ's EJ guidance;
- Designating a Chief EJ Officer for each MILDEP;
- Coordinating with the MILDEPs and DoD Components on the best methods to integrate EJ into existing programming, planning, acquisition, and other actions;
- Issuing a DoD Directive, Instruction, and/or Manual, describing consistent EJ implementation across all programs and services and identifying actions better managed at the OSD-level versus the MILDEP- and installation-levels;

- Developing EJ training and communication materials for DoD leadership; and
- Beginning integration of available EJ tools into planning documents.

Dated: June 6, 2024.
Patricia L. Toppings,
OSD Federal Register Liaison Officer,
Department of Defense.
[FR Doc. 2024–12775 Filed 6–10–24; 8:45 am]
BILLING CODE 6001–FR–P

DENALI COMMISSION

Denali Commission Fiscal Year 2025 Draft Work Plan

AGENCY: Denali Commission.
ACTION: Notice.

SUMMARY: The Denali Commission (Commission) is an independent Federal agency based on an innovative Federal-State partnership designed to provide critical utilities, infrastructure and support for economic development and training in Alaska by delivering federal services in the most cost-effective manner possible. The Commission is required to develop an annual work plan for future spending which will be published in the **Federal Register**, providing an opportunity for a 30-day period of public review and written comment. This **Federal Register** notice serves to announce the 30-day opportunity for public comment on the Denali Commission Draft Work Plan for Federal Fiscal Year 2025 (FY 2025).

DATES: Comments and related material to be received by, July 11, 2024.

ADDRESSES: Submit comments to the Denali Commission, Attention: Elinda Hetemi, 550 W 7th Avenue, Suite 1230, Anchorage, AK 99501.

FOR FURTHER INFORMATION CONTACT: Elinda Hetemi, Denali Commission, 550 W 7th Avenue, Suite 1230, Anchorage, AK 99501. Telephone: 907–271–3415. Email: ehetemi@denali.gov.

SUPPLEMENTARY INFORMATION:
Background: The Denali Commission’s mission is to partner with Tribal, Federal, State, and local governments and collaborate with all Alaskans to improve the effectiveness and efficiency of government services, to build and ensure the operation and maintenance of Alaska’s basic infrastructure, and to develop a well-trained labor force employed in a diversified and sustainable economy.

By creating the Commission, Congress mandated that all parties involved partner together to find new and innovative solutions to the unique infrastructure and economic

development challenges in America’s most remote communities. Pursuant to the Denali Commission Act, the Commission determines its own basic operating principles and funding criteria on an annual federal fiscal year (October 1 to September 30) basis. The Commission outlines these priorities and funding recommendations in an annual work plan. The FY 2025 Work Plan was developed in the following manner.

- At a meeting of the Denali Commissioners the Commissioners voted to adopt the FY 2025 Workplan.
- The work plan was published on *Denali.gov* for review by the public in advance of public testimony.
- A public hearing was held to record public comments and recommendations on the preliminary draft work plan.
- No public comments were received.
- The Federal Co-Chair prepared the draft work plan for publication in the **Federal Register** providing a 30-day period for public review and written comment. During this time, the draft work plan will also be disseminated to Commission program partners including, but not limited to, the Bureau of Indian Affairs (BIA), the Economic Development Administration (EDA), Department of Agriculture—Rural Utilities Service (USDA/RUS), and the State of Alaska.
- At the conclusion of the **Federal Register** public comment period Commission staff will provide the Federal Co-Chair with a summary of public comments and recommendations, if any, on the draft work plan.
- If no revisions are made to the draft, the Federal Co-Chair will provide notice of approval of the work plan to the Commissioners, and forwards the work plan to the Secretary of Commerce for approval; or, if there are revisions the Federal Co-Chair provides notice of modifications to the Commissioners for their consideration and approval, and upon receipt of approval from Commissioners, forwards the work plan to the Secretary of Commerce for approval.
- The Secretary of Commerce approves the work plan.
- The Federal Co-Chair then approves grants and contracts based upon the approved work plan.

FY 2025 Appropriations Summary

The Commission has historically received federal funding from several sources. The two primary sources at this time include the Energy & Water Appropriation Bill (“base” or “discretionary” funds), Transportation Housing and Urban Development

(THUD) and an annual allocation from the Trans-Alaska Pipeline Liability (TAPL) fund. The proposed FY 2025 Work Plan assumes the Commission will receive \$15,000,000 of base funds, which is the amount referenced in the reauthorization of the Commission passed by Congress in 2016 (ref: Pub. L. 114–322), \$18,000,000 from THUD, less administrative expenses, and a \$2,917,000 TAPL allocation based on discussions with the Office of Management and Budget (OMB). Approximately \$4,000,000 of the base funds will be used for administrative expenses and non-project program support. The total base funding shown in the Work Plan also includes an amount typically available from project closeouts and other de-obligations that occur in any given year. Approximately \$117,000 of the TAPL funds will be utilized for administrative expenses and non-project program support, leaving \$2,800,000 available for program activities. Absent any new specific direction or limitations provided by Congress these funding sources are governed by the following general principles, either by statute or by language in the Work Plan itself:

- Funds from the Energy & Water Appropriation are eligible for use in all programs.
- TAPL funds can only be used for bulk fuel related projects and activities while THUD funds can only be used for Transportation.
- Appropriated funds may be reduced due to Congressional action, rescissions by OMB, and other federal agency actions.
- All investment amounts identified in the work plan, are “up to” amounts, and may be reassigned to other programs included in the current year work plan, if they are not fully expended in a program component area or a specific project.
- Funds set aside for administrative expenses that subsequently become available, may be used for program activities included in the current year work plan.

DENALI COMMISSION FY 2025 FUNDING SUMMARY

Source	Available for program activities
Energy and Water Funds	\$13,000,000
TAPL Funds	2,800,000
THUD Funds	17,800,000
Grand Total	33,600,000

Notes:

¹ If the final appropriation is less than indicated the Federal Co-Chair shall reduce investments to balance the FY 2025 Work Plan.

	Base	TAPL	THUD	Total
<i>Energy Reliability and Security:</i>				
Diesel Power Plants and Interties	\$3,700,000			\$3,700,000
Wind, Hydro, Biomass, Other Proven Renewables and Emerging Technologies	800,000			800,000
Audits, TA, & Community Energy Efficiency Improvements	400,000			400,000
RPSU Maintenance and Improvement Projects	1,000,000			1,000,000
Subtotal	5,900,000			5,900,000
<i>Bulk Fuel Safety and Security:</i>				
New/Refurbished Facilities		1,500,000		1,500,000
Maintenance and Improvement Projects		700,000		700,000
Subtotal		2,200,000		2,200,000
<i>Village Infrastructure Protection</i>	1,500,000			1,500,000
<i>Transportation:</i>				
Surface Transportation			13,300,000	13,300,000
Waterfront Improvements			4,500,000	4,500,000
Subtotal			17,800,000	17,900,000
<i>Sanitation:</i>				
Village Water, Wastewater and Solid Waste	1,500,000			1,500,000
Subtotal	1,500,000			1,500,000
<i>Community Facilities:</i>				
Housing	1,000,000			1,000,000
Health and Wellness	500,000			500,000
Subtotal	1,500,000			1,500,000
<i>Broadband</i>	250,000			250,000
<i>Workforce Development:</i>				
Energy and Bulk Fuel	300,000	600,000		900,000
Other	1,000,000			1,000,000
Subtotal	1,300,000	600,000		1,900,000
<i>Flexible Funding</i>	2,050,000			2,050,000
Subtotal	1,050,000			1,050,000
Totals	13,000,000	2,800,000	17,800,000	33,600,000

Authority: Public Law 105–277 sec. 304(b)(1).

Anne Stanislawski,
Administrative Officer.

[FR Doc. 2024–12698 Filed 6–10–24; 8:45 am]

BILLING CODE 3300–01–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2024–SCC–0080]

Agency Information Collection Activities; Comment Request; Evaluation of the REL Southeast Early Literacy Toolkit

AGENCY: Institute of Education Sciences (IES), Department of Education (ED).

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act (PRA) of 1995, the Department is proposing a new information collection request (ICR).

DATES: Interested persons are invited to submit comments on or before August 12, 2024.

ADDRESSES: To access and review all the documents related to the information collection listed in this notice, please use <http://www.regulations.gov> by searching the Docket ID number ED–2024–SCC–0080. Comments submitted in response to this notice should be submitted electronically through the Federal eRulemaking Portal at <http://www.regulations.gov> by selecting the Docket ID number or via postal mail, commercial delivery, or hand delivery. If the www.regulations.gov site is not available to the public for any reason, the Department will temporarily accept comments at ICDocketMgr@ed.gov. Please include the docket ID number and the title of the information collection request when requesting documents or submitting comments. Please note that comments submitted after the comment period will not be accepted. Written requests for

information or comments submitted by postal mail or delivery should be addressed to the Manager of the Strategic Collections and Clearance Governance and Strategy Division, U.S. Department of Education, 400 Maryland Ave. SW, LBJ, Room 6W203, Washington, DC 20202–8240.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Janelle Sands, 202–245–6786.

SUPPLEMENTARY INFORMATION: The Department, in accordance with the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3506(c)(2)(A)), provides the general public and Federal agencies with an opportunity to comment on proposed, revised, and continuing collections of information. This helps the Department assess the impact of its information collection requirements and minimize the public's reporting burden. It also helps the public understand the Department's information collection requirements and provide the requested

data in the desired format. The Department is soliciting comments on the proposed information collection request (ICR) that is described below. The Department is especially interested in public comment addressing the following issues: (1) is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology. Please note that written comments received in response to this notice will be considered public records.

Title of Collection: Evaluation of the REL Southeast Early Literacy Toolkit.

OMB Control Number: 1850–NEW.

Type of Review: A new ICR.

Respondents/Affected Public: Individuals and Households.

Total Estimated Number of Annual Responses: 1,330.

Total Estimated Number of Annual Burden Hours: 322.

Abstract: The U.S. Department of Education is supporting the development and evaluation of a toolkit that will support the implementation of effectively differentiated reading instruction for students in grades K–3. This toolkit is based on evidence-based recommendation in the Assisting Students Struggling with Reading: Response to Intervention (RtI) and Multi-Tier Intervention in the Primary Grades practice guide. The evaluation will rigorously test the efficacy of the toolkit in improving explicit instruction, classroom management, and use of student data as well as student learning outcomes in grades K–3 English language arts. The evaluation will use a blocked randomized control trial design in which districts are blocks and schools are randomly assigned to receive the toolkit or not. The evaluation will be conducted in 20 Florida schools during the 2025/26 school year.

The evaluation will focus on measuring the toolkit's impact on three teacher-level outcomes: explicit instruction, classroom management, and data use to inform instruction during small group time. The evaluation also will examine the impact of the toolkit on students' foundational reading skills.

In addition to collecting data to measure teacher and student outcomes, the evaluation team will collect data to document the implementation of the toolkit in treatment schools and the

service contrast between treatment and control schools, and to describe the characteristics of participating schools, teachers, and students at baseline.

The evaluation will produce a publicly available report that summarizes evaluation findings. The findings from the evaluation will inform further refinement of the toolkit, to be released to the public after the evaluation.

Dated: June 6, 2024.

Juliana Pearson,

PRA Coordinator, Strategic Collections and Clearance, Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2024–12765 Filed 6–10–24; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2024–SCC–0054]

Agency Information Collection Activities; Submission to the Office of Management and Budget for Review and Approval; Comment Request; Reaffirmation Agreement

AGENCY: Federal Student Aid (FSA), Department of Education (ED).

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act (PRA) of 1995, the Department is proposing an extension without change of a currently approved information collection request (ICR).

DATES: Interested persons are invited to submit comments on or before July 11, 2024.

ADDRESSES: Written comments and recommendations for proposed information collection requests should be submitted within 30 days of publication of this notice. Click on this link www.reginfo.gov/public/do/PRAMain to access the site. Find this information collection request (ICR) by selecting “Department of Education” under “Currently Under Review,” then check the “Only Show ICR for Public Comment” checkbox. *Reginfo.gov* provides two links to view documents related to this information collection request. Information collection forms and instructions may be found by clicking on the “View Information Collection (IC) List” link. Supporting statements and other supporting documentation may be found by clicking on the “View Supporting Statement and Other Documents” link.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection

activities, please contact Beth Grebeldinger, 202–570–8414.

SUPPLEMENTARY INFORMATION: The Department is especially interested in public comment addressing the following issues: (1) is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology. Please note that written comments received in response to this notice will be considered public records.

Title of Collection: Reaffirmation Agreement.

OMB Control Number: 1845–0133.

Type of Review: An extension without change of a currently approved ICR.

Respondents/Affected Public: Individuals and Households; Private Sector; State, Local, and Tribal Governments.

Total Estimated Number of Annual Responses: 8,594.

Total Estimated Number of Annual Burden Hours: 1,032.

Abstract: The Higher Education Act of 1965, as amended (HEA), established the Federal Family Education Loan (FFEL) Program, and the William D. Ford Federal Direct Loan (Direct Loan) Program under Title IV, Parts B and D respectively. The HEA provides for a maximum loan amount that a borrower can receive per year and in total. If a borrower receives more than the maximum amount, the borrower becomes ineligible for further Title IV aid (including Federal Pell Grants, Federal Supplemental Educational Opportunity Grants, Federal Work-Study, and Teacher Education Assistance for Higher Education (TEACH) Grants, Iraq and Afghanistan Service Grants) unless the borrower repays the excess amount or agrees to repay the excess amount according to the terms and conditions of the promissory note that the borrower signed. Agreeing to repay the excess amount according to the terms and conditions of the promissory note that the borrower signed is called reaffirmation, which is the subject of this collection. This renewal without change of the information collection is necessary for the Department of Education (the Department), as a holder of some FFEL Program loans and all Direct Loans, and all FFEL Program lenders to capture the borrowers formal

agreement to repay any excess amount of FFEL or Direct Loan program loans that the borrower received according to the terms and conditions of the promissory note the borrower signed. The form has not been changed since its last update.

Dated: June 5, 2024.

Kun Mullan,

PRA Coordinator, Strategic Collections and Clearance, Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2024-12671 Filed 6-10-24; 8:45 am]

BILLING CODE 4000-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric corporate filings:

Docket Numbers: EC24-82-000.

Applicants: SR Ailey, LLC.

Description: Application for authorization under Section 203 of the Federal Power Act of SR Ailey, LLC.

Filed Date: 6/4/24.

Accession Number: 20240604-5289.

Comment Date: 5 p.m. ET 6/25/24.

Docket Numbers: EC24-83-000.

Applicants: SR Toombs, LLC.

Description: Application for authorization under Section 203 of the Federal Power Act of SR Toombs, LLC.

Filed Date: 6/4/24.

Accession Number: 20240604-5294.

Comment Date: 5 p.m. ET 6/25/24.

Docket Numbers: EC24-84-000.

Applicants: Avangrid, Inc., Iberdrola, S.A.

Description: Joint application for authorization under Section 203 of the Federal Power Act of Iberdrola, S.A., et al. under.

Filed Date: 6/3/24.

Accession Number: 20240603-5276.

Comment Date: 5 p.m. ET 6/24/24.

Take notice that the Commission received the following exempt wholesale generator filings:*Docket Numbers:* EG24-199-000.

Applicants: Callisto I Energy Center LLC.

Description: Callisto I Energy Center LLC submits notice of self-certification of exempt wholesale generator status.

Filed Date: 6/5/24.

Accession Number: 20240605-5149.

Comment Date: 5 p.m. ET 6/26/24.

Take notice that the Commission received the following Complaints and

Compliance filings in EL Dockets:*Docket Numbers:* EL24-115-000.

Applicants: California Public Utilities Commission, et al. v. San Diego Gas & Electric Company.

Description: Complaint of California Public Utilities Commission, et al. v. San Diego Gas & Electric Company.

Filed Date: 5/31/24.

Accession Number: 20240531-5455.

Comment Date: 5 p.m. ET 7/1/24.

Take notice that the Commission received the following electric rate filings:*Docket Numbers:* ER22-290-007.

Applicants: Oakland Power Company LLC.

Description: Compliance filing: Tariff Record Priority Order Adjustment Compliance Filing to be effective 1/1/2022.

Filed Date: 6/5/24.

Accession Number: 20240605-5089.

Comment Date: 5 p.m. ET 6/26/24.

Docket Numbers: ER22-290-008.

Applicants: Oakland Power Company LLC.

Description: Compliance filing: Errata to Hourly Capital Item Charge Update Filing to be effective 8/1/2023.

Filed Date: 6/5/24.

Accession Number: 20240605-5092.

Comment Date: 5 p.m. ET 6/26/24.

Docket Numbers: ER23-254-003.

Applicants: Oakland Power Company LLC.

Description: Compliance filing: Compliance Filing Pursuant to Order Approving Settlement to be effective 1/1/2023.

Filed Date: 6/5/24.

Accession Number: 20240605-5104.

Comment Date: 5 p.m. ET 6/26/24.

Docket Numbers: ER24-1431-001.

Applicants: Southwestern Public Service Company.

Description: Tariff Amendment: 2024.06.05 SPS Responded to Deficiency Letter in ER24-1431 to be effective 5/8/2024.

Filed Date: 6/5/24.

Accession Number: 20240605-5157.

Comment Date: 5 p.m. ET 6/26/24.

Docket Numbers: ER24-1434-001.

Applicants: Central Hudson Gas & Electric Corporation, New York Independent System Operator, Inc.

Description: Tariff Amendment: Central Hudson Gas & Electric Corporation submits tariff filing per 35.17(b): Central Hudson Deficiency Response re: Rate Schedule 21 Formula Rate Filing to be effective 8/5/2024.

Filed Date: 6/5/24.

Accession Number: 20240605-5161.

Comment Date: 5 p.m. ET 6/26/24.

Docket Numbers: ER24-2187-000.

Applicants: American Electric Power Service Corporation, PJM Interconnection, L.L.C.

Description: § 205(d) Rate Filing: American Electric Power Service Corporation submits tariff filing per 35.13(a)(2)(iii): AEP submits one Facilities Agreement re: ILDSA, SA No. 5120 to be effective 8/5/2024.

Filed Date: 6/5/24.

Accession Number: 20240605-5054.

Comment Date: 5 p.m. ET 6/26/24.

Docket Numbers: ER24-2188-000.

Applicants: Southwest Power Pool, Inc.

Description: § 205(d) Rate Filing: 1276R33 Evergy Metro NITSA NOA to be effective 6/1/2024.

Filed Date: 6/5/24.

Accession Number: 20240605-5119.

Comment Date: 5 p.m. ET 6/26/24.

Docket Numbers: ER24-2189-000.

Applicants: Midcontinent Independent System Operator, Inc., American Transmission Company LLC.

Description: § 205(d) Rate Filing: Midcontinent Independent System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii): 2024-06-05_SA 4300 ATC-WPL E&P (J1706) to be effective 8/5/2024.

Filed Date: 6/5/24.

Accession Number: 20240605-5127.

Comment Date: 5 p.m. ET 6/26/24.

Docket Numbers: ER24-2190-000.

Applicants: Southwest Power Pool, Inc.

Description: § 205(d) Rate Filing: 1266R15 Kansas Municipal Energy Agency NITSA and NOA to be effective 6/1/2024.

Filed Date: 6/5/24.

Accession Number: 20240605-5176.

Comment Date: 5 p.m. ET 6/26/24.

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: June 5, 2024.
Debbie-Anne A. Reese,
Acting Secretary.
[FR Doc. 2024–12751 Filed 6–10–24; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 1889–085; Project No. 2485–071]

FirstLight MA Hydro LLC; Northfield Mountain LLC; Notice of Intent To Prepare an Environmental Impact Statement

On April 29, 2016, and materially amended on December 4, 2020, FirstLight MA Hydro LLC and Northfield Mountain LLC, respectively, filed applications for new major licenses to operate the 62.0-megawatt (MW) Turners Falls Hydroelectric Project (Turners Falls Project; FERC No. 1889) and 1,166.8–MW Northfield Mountain Pumped Storage Project (Northfield Mountain Project; FERC No. 2485) (collectively, projects). The projects are located on the Connecticut River in Windham County, Vermont; Cheshire County, New Hampshire; and Franklin County, Massachusetts. The Turners Falls Project boundary includes the approximately 20-acre Silvio Conte Anadromous Fish Laboratory, which is administered by the U.S. Geological Survey.

During the application pre-filing process, on December 21, 2012, Commission staff issued Scoping Document 1, initiating the scoping process for the projects in accordance with the National Environmental Policy Act (NEPA) and Commission regulations. On April 15, 2013, Commission staff issued a revised scoping document (Scoping Document 2). In accordance with the Commission’s regulations, on February 22, 2024, Commission staff issued notices that the

projects were ready for environmental analysis (REA Notice). Based on the information in the record, including comments filed during scoping and in response to the REA Notices, staff has determined that relicensing the project may constitute a major Federal action significantly affecting the quality of the human environment. Therefore, staff intends to prepare an Environmental Impact Statement (EIS) for the above-captioned projects.

A draft EIS will be issued and circulated for review by all interested parties. All comments filed in response to the REA notices, and on the draft EIS will be analyzed by staff in a final EIS. Staff’s conclusions and recommendations will be available for the Commission’s consideration in reaching its final licensing decision.

The application will be processed according to the following schedule. Revisions to the schedule may be made as appropriate.

Milestone	Target date
Issue draft EIS	December 2024.
Draft EIS Public Meeting.	January 2025.
Comments on draft EIS due.	February 2025.
Commission issues final EIS.	August 2025. ¹

Any questions regarding this notice may be directed to Steve Kartalia at (202) 502–6131 or *stephen.kartalia@ferc.gov*.

Dated: June 5, 2024.
Debbie-Anne A. Reese,
Acting Secretary.
[FR Doc. 2024–12756 Filed 6–10–24; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric corporate filings:

Docket Numbers: EC24–80–000.
Applicants: Maple Flats Solar Energy Center LLC, WEC Infrastructure LLC.
Description: Joint Application for Authorization Under Section 203 of the

¹ The Council on Environmental Quality’s (CEQ) regulations under 40 CFR 1501.10(b)(2) (2023) require that EISs be completed within 2 years of the Federal action agency’s decision to prepare an EIS. See also National Environmental Policy Act, 42 U.S.C. 4321 *et seq.*, amended by section 107(g)(1)(A)(iii) of the Fiscal Responsibility Act of 2023, Public Law 118–5, sec. 4336a, 137 Stat. 42.

Federal Power Act of Maple Flats Solar Energy Center LLC, et al.

Filed Date: 5/23/24.
Accession Number: 20240523–5228.
Comment Date: 5 p.m. ET 7/8/24.

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER22–2948–000.
Applicants: Puget Sound Energy, Inc.
Description: Motion to Accept Report Out of Time of Puget Sound Energy, Inc.
Filed Date: 9/23/22.
Accession Number: 20220923–5221.
Comment Date: 5 p.m. ET 6/25/24.

Docket Numbers: ER24–697–001.
Applicants: Westlands Solar Blue (OZ) Owner, LLC.

Description: Refund Report: Refund Report and Request for Confidential Treatment to be effective N/A.
Filed Date: 6/4/24.

Accession Number: 20240604–5014.
Comment Date: 5 p.m. ET 6/25/24.

Docket Numbers: ER24–698–001.
Applicants: Castanea Project, LLC.
Description: Refund Report: Refund Report and Request for Confidential Treatment to be effective N/A.

Filed Date: 6/4/24.
Accession Number: 20240604–5016.
Comment Date: 5 p.m. ET 6/25/24.

Docket Numbers: ER24–1697–000.
Applicants: AES Westwing II ES, LLC.
Description: Supplement to 04/04/2024, AES Westwing II ES, LLC tariff filing.

Filed Date: 5/31/24.
Accession Number: 20240531–5454.
Comment Date: 5 p.m. ET 6/10/24.

Docket Numbers: ER24–2180–000.
Applicants: PJM Interconnection, L.L.C.

Description: Tariff Amendment: Notice of Cancellation of Two ISAs, SA Nos. 2833 and 2834 to be effective 5/3/2024.

Filed Date: 6/3/24.
Accession Number: 20240603–5228.
Comment Date: 5 p.m. ET 6/24/24.

Docket Numbers: ER24–2181–000.
Applicants: Public Service Company of Colorado.

Description: § 205(d) Rate Filing: 2024–06–03 FRMS–GI–2014–6–LGIA Amnd 3–458–0.0.0 to be effective 6/4/2024.

Filed Date: 6/3/24.
Accession Number: 20240603–5235.
Comment Date: 5 p.m. ET 6/24/24.

Docket Numbers: ER24–2182–000.
Applicants: Public Service Company of Colorado.

Description: § 205(d) Rate Filing: 2024–06–03 FRMS–GI–2014–6–Surplus LGIA Amnd 2–584–0.2.0 to be effective 6/4/2024.

Filed Date: 6/3/24.

Accession Number: 20240603–5240.

Comment Date: 5 p.m. ET 6/24/24.

Docket Numbers: ER24–2183–000.

Applicants: Big Rock ESS Assets LLC.

Description: Baseline eTariff Filing:

Big Rock ESS Assets LLC MBR

Application Filing to be effective 8/3/2024.

Filed Date: 6/4/24.

Accession Number: 20240604–5106.

Comment Date: 5 p.m. ET 6/25/24.

Docket Numbers: ER24–2184–000.

Applicants: Southwest Power Pool, Inc.

Description: § 205(d) Rate Filing: Revisions to Expand the RTO into the Western Interconnection (Part 1 of 2) to be effective 12/31/9998.

Filed Date: 6/4/24.

Accession Number: 20240604–5135.

Comment Date: 5 p.m. ET 6/25/24.

Docket Numbers: ER24–2185–000.

Applicants: Southwest Power Pool, Inc.

Description: § 205(d) Rate Filing: Revisions to Expand the RTO into the Western Interconnection (Part 2 of 2) to be effective 12/31/9998.

Filed Date: 6/4/24.

Accession Number: 20240604–5138.

Comment Date: 5 p.m. ET 6/25/24.

Docket Numbers: ER24–2186–000.

Applicants: Southwest Power Pool, Inc., NorthWestern Energy Public Service Corporation.

Description: § 205(d) Rate Filing: Southwest Power Pool, Inc. submits tariff filing per 35.13(a)(2)(iii): NorthWestern Energy—Formula Rates Revisions to be effective 1/1/2024.

Filed Date: 6/4/24.

Accession Number: 20240604–5189.

Comment Date: 5 p.m. ET 6/25/24.

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: June 4, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024–12681 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 1904–078; Project No. 1855–050; Project No. 1892–030]

Great River Hydro, LLC; Notice of Intent To Prepare an Environmental Impact Statement

On May 1, 2017, and materially amended on December 7, 2020, Great River Hydro, LLC filed applications for new major licenses to operate its 32.4-megawatt (MW) Vernon Hydroelectric Project (Vernon Project; FERC No. 1904), 40.8–MW Bellows Falls Hydroelectric Project (Bellows Falls Project; FERC No. 1855), and 35.6–MW Wilder Hydroelectric Project (Wilder Project; FERC No. 1892 (collectively, projects). The projects are located on the Connecticut River in Orange, Windsor, and Windham Counties, Vermont; and Grafton, Sullivan, and Cheshire Counties, New Hampshire.

During the application pre-filing process, on December 21, 2012, Commission staff issued Scoping Document 1, initiating the scoping process for the projects in accordance with the National Environmental Policy Act (NEPA) and Commission regulations. On April 15, 2013, Commission staff issued a revised scoping document (Scoping Document 2). In accordance with the Commission's regulations, on February 22, 2024, Commission staff issued notices that the projects were ready for environmental analysis (REA Notice). Based on the information in the record, including comments filed during scoping and in response to the REA Notices, staff has determined that relicensing the project

may constitute a major Federal action significantly affecting the quality of the human environment. Therefore, staff intends to prepare an Environmental Impact Statement (EIS) for the above-captioned projects.

A draft EIS will be issued and circulated for review by all interested parties. All comments filed in response to the REA notices, and on the draft EIS, will be analyzed by staff in a final EIS. Staff's conclusions and recommendations will be available for the Commission's consideration in reaching its final licensing decision.

The application will be processed according to the following schedule. Revisions to the schedule may be made as appropriate.

Milestone	Target date
Issue draft EIS	December 2024.
Draft EIS Public Meeting.	January 2025.
Comments on draft EIS due.	February 2025.
Commission issues final EIS.	August 2025. ¹

Any questions regarding this notice may be directed to Steve Kartalia at (202) 502–6131 or stephen.kartalia@ferc.gov.

Dated: June 5, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024–12760 Filed 6–10–24; 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: RP24–822–000.

Applicants: Dauphin Island Gathering Partners.

Description: § 4(d) Rate Filing: W&T—IT Agreement 2024 to be effective 5/28/2024.

Filed Date: 6/3/24.

Accession Number: 20240603–5145.

Comment Date: 5 p.m. ET 6/17/24.

Docket Numbers: RP24–823–000.

¹ The Council on Environmental Quality's (CEQ) regulations under 40 CFR 1501.10(b)(2) (2023) require that EISs be completed within 2 years of the Federal action agency's decision to prepare an EIS. See also National Environmental Policy Act, 42 U.S.C. 4321 *et seq.*, amended by section 107(g)(1)(A)(iii) of the Fiscal Responsibility Act of 2023, Public Law 118–5, sec. 4336a, 137 Stat. 42.

Applicants: Cheniere Corpus Christi Pipeline, LP.

Description: § 4(d) Rate Filing: Cheniere Corpus Christi EPC Rate Change to be effective 8/1/2024.

Filed Date: 6/3/24.

Accession Number: 20240603–5149.

Comment Date: 5 p.m. ET 6/17/24.

Docket Numbers: RP24–824–000.

Applicants: Natural Gas Pipeline Company of America LLC.

Description: § 4(d) Rate Filing: Negotiated Rate Agreements Filings—Various Shippers on 06/04/2024 to be effective 7/1/2024.

Filed Date: 6/4/24.

Accession Number: 20240604–5064.

Comment Date: 5 p.m. ET 6/17/24.

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: RP24–805–001.

Applicants: Tennessee Gas Pipeline Company, L.L.C.

Description: Tariff Amendment: Amendment to Negotiated Rate and Non-Conforming Agreements Filing to be effective 7/1/2024.

Filed Date: 6/3/24.

Accession Number: 20240603–5183.

Comment Date: 5 p.m. ET 6/17/24.

Any person desiring to protest in any of 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: June 4, 2024,

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024–12680 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2600–000]

**Bangor-Pacific Hydro Associates;
Notice of Authorization for Continued
Project Operation**

The license for the West Enfield Hydroelectric Project No. 2600 was issued for a period ending May 31, 2024.

Section 15(a)(1) of the FPA, 16 U.S.C. 808(a)(1), requires the Commission, at the expiration of a license term, to issue from year-to-year an annual license to the then licensee(s) under the terms and conditions of the prior license until a new license is issued, or the project is otherwise disposed of as provided in section 15 or any other applicable section of the FPA. If the project’s prior license waived the applicability of section 15 of the FPA, then, based on section 9(b) of the Administrative Procedure Act, 5 U.S.C. 558(c), and as set forth at 18 CFR 16.21(a), if the licensee of such project has filed an application for a subsequent license, the licensee may continue to operate the project in accordance with the terms and conditions of the license after the minor or minor part license expires, until the Commission acts on its application. If the licensee of such a project has not filed an application for a subsequent license, then it may be required, pursuant to 18 CFR 16.21(b), to continue project operations until the Commission issues someone else a license for the project or otherwise orders disposition of the project.

If the project is subject to section 15 of the FPA, notice is hereby given that an annual license for Project No. 2600 is issued to Bangor-Pacific Hydro Associates for a period effective June 1, 2024, through May 31, 2025, or until the issuance of a new license for the project or other disposition under the FPA, whichever comes first.

If issuance of a new license (or other disposition) does not take place on or before May 31, 2025, notice is hereby given that, pursuant to 18 CFR 16.18(c), an annual license under section 15(a)(1) of the FPA is renewed automatically without further order or notice by the Commission, unless the Commission orders otherwise.

If the project is not subject to section 15 of the FPA, notice is hereby given that Bangor-Pacific Hydro Associates is authorized to continue operation of the West Enfield Hydroelectric Project under the terms and conditions of the prior license until the issuance of a subsequent license for the project or other disposition under the FPA, whichever comes first.

Dated: June 5, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024–12755 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 7189–015]

**Green Lake Water Power Company;
Notice of Revised Procedural Schedule
for Environmental Assessment for the
Proposed Project Relicense**

On March 31, 2022, Green Lake Water Power Company filed an application for a subsequent license to continue to operate and maintain the 424-kilowatt Green Lake Hydroelectric Project No. 7189 (Green Lake Project). On May 31, 2023, Commission staff issued a notice of intent to prepare an environmental assessment (EA) to evaluate the effects of relicensing the Green Lake Project. The notice included an anticipated schedule for issuing the EA. By notice issued April 11, 2024, the schedule for completing the EA was revised. The revised due date for the EA was to be May 2024.

On May 28, 2024, the Maine Department of Environmental Protection filed its Clean Water Act section 401 water quality certification (certification) for the Green Lake Project with the Commission. In order for staff to fully consider the certification, the procedural schedule for completing the EA is being revised as follows. Further revisions to the schedule may be made as appropriate.

Milestone	Target date
Issue EA	September 2024.

Any questions regarding this notice may be directed to Amanda Gill at (202) 502-6773, or by email at amanda.gill@ferc.gov.

Dated: June 4, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

[FR Doc. 2024-12676 Filed 6-10-24; 8:45 am]

BILLING CODE 6717-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 1922-052]

Ketchikan Public Utilities; Notice of Revised Procedural Schedule for Draft and Final Environmental Assessment for the Proposed Project Relicense

On October 27, 2022, Ketchikan Public Utilities (KPU) filed an application for a new major license for the 7.1-megawatt Beaver Falls Hydroelectric Project (Beaver Falls Project; FERC No. 1922). On January 5, 2024, Commission staff issued a notice of intent to prepare a draft and final Environmental Assessment (EA) to evaluate the effects of relicensing the Beaver Falls Project. The notice of intent included an anticipated schedule for issuing the draft and final EA. By this notice, Commission staff is updating the procedural schedule for completing the draft and final EAs. The revised schedule is shown below. Further revisions to the schedule may be made as appropriate.

Milestone	Target date
Commission issues draft EA.	August 2024.
Comments on draft EA.	September 2024.
Commission issues final EA.	January 2025. ¹

Any questions regarding this notice may be directed to Golbahar Mirhosseini at Golbahar.Mirhosseini@ferc.gov.

Dated: June 4, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

[FR Doc. 2024-12677 Filed 6-10-24; 8:45 am]

BILLING CODE 6717-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RM98-1-000]

Records Governing Off-the-Record Communications; Public Notice

This constitutes notice, in accordance with 18 CFR 385.2201(b), of the receipt of prohibited and exempt off-the-record communications.

Order No. 607 (64 FR 51222, September 22, 1999) requires Commission decisional employees, who make or receive a prohibited or exempt off-the-record communication relevant to the merits of a contested proceeding, to deliver to the Secretary of the Commission, a copy of the communication, if written, or a summary of the substance of any oral communication.

Prohibited communications are included in a public, non-decisional file

associated with, but not a part of, the decisional record of the proceeding. Unless the Commission determines that the prohibited communication and any responses thereto should become a part of the decisional record, the prohibited off-the-record communication will not be considered by the Commission in reaching its decision. Parties to a proceeding may seek the opportunity to respond to any facts or contentions made in a prohibited off-the-record communication and may request that the Commission place the prohibited communication and responses thereto in the decisional record. The Commission will grant such a request only when it determines that fairness so requires. Any person identified below as having made a prohibited off-the-record communication shall serve the document on all parties listed on the official service list for the applicable proceeding in accordance with Rule 2010, 18 CFR 385.2010.

Exempt off-the-record communications are included in the decisional record of the proceeding, unless the communication was with a cooperating agency as described by 40 CFR 1501.6, made under 18 CFR 385.2201(e)(1)(v).

The following is a list of off-the-record communications recently received by the Secretary of the Commission. Each filing may be viewed on the Commission's website at <http://www.ferc.gov> using the eLibrary link. Enter the docket number, excluding the last three digits, in the docket number field to access the document. For assistance, please contact FERC Online Support at FERCOnlineSupport@ferc.gov or toll free at (866) 208-3676, or for TTY, contact (202) 502-8659.

Docket Nos.	File date	Presenter or requester
Prohibited:		
1. P-14861-002	5-21-2024	FERC Staff. ¹
2. P-248 5 071	5-21-2024	FERC Staff. ²
3. EL18-152-003	5-28-2024	FERC Staff. ³
Exempt:		
1. P-2411-030	5-23-2024	FERC Staff. ⁴
2. ER23-729-000	6-3-2024	U.S. Congress. ⁵
EL23-19-000.		

¹ Comments dated 5/13/24 of St. Michael & All Angels Episcopal Church.

² Emailed comments dated 5/20/24 of Seneca Smith.

³ Emailed comments dated 5/28/24 of Davante Lewis.

⁴ Emailed communication dated 5/02/24 of Mel Vernon.

⁵ U.S. Senators' Benjamin L. Cardin and Chris Van Hollen; U.S. Representatives' Steny H. Hoyer, John P. Sarbanes, Andy Harris, M.D., Jamie Raskin, David J. Trone, Glenn Ivey, and C.A. Dutch Ruppersberger.

¹ The Council on Environmental Quality's (CEQ) regulations under 40 CFR 1501.10(b)(1) (2022) require that EAs be completed within 1 year of the

Federal action agency's decision to prepare an EA. See National Environmental Policy Act, 42 U.S.C. 4321 *et seq.*, as amended by section 107(g)(1)(B)(iii)

of the Fiscal Responsibility Act of 2023, Public Law 118-5, sec. 4336a, 137 Stat. 42.

Dated: June 4, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024–12675 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP24–473–000]

Cheniere Corpus Christi Pipeline, LP; Notice of Request Under Blanket Authorization and Establishing Intervention and Protest Deadline

Take notice that on May 31, 2024, Cheniere Corpus Christi Pipeline, L.P. (CCPL), 845 Texas Avenue, Suite 1250, Houston, Texas 77002, filed in the above-referenced docket a prior notice request, pursuant to sections 157.205 and 157.216(b) of the Commission's regulations under the Natural Gas Act (NGA) and CCPL's blanket certificate issued in Docket No. CP12–508–000, for authorization to abandon by transfer to Corpus Christi Liquefaction, LLC approximately 3,700 linear feet of 36- and 48-inch-diameter pipeline segments and ancillary facilities in San Patricio County, Texas, all as more fully set forth in the request which is on file with the Commission and open to public inspection.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (<http://www.ferc.gov>). From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at public.referenceroom@ferc.gov.

Any questions concerning this request should be directed to Joseph Moake, Director, Regulatory Project Strategy, Cheniere Corpus Christi Pipeline, L.P.,

845 Texas Avenue, Suite 1250, Houston, Texas 77002, by telephone at (832) 870–9956, or by email at joseph.moake@cheniere.com.

Public Participation

There are three ways to become involved in the Commission's review of this project: you can file a protest to the project, you can file a motion to intervene in the proceeding, and you can file comments on the project. There is no fee or cost for filing protests, motions to intervene, or comments. The deadline for filing protests, motions to intervene, and comments is 5:00 p.m. Eastern Time on August 5, 2024. How to file protests, motions to intervene, and comments is explained below.

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.

Protests

Pursuant to section 157.205 of the Commission's regulations under the NGA,¹ any person² or the Commission's staff may file a protest to the request. If no protest is filed within the time allowed or if a protest is filed and then withdrawn within 30 days after the allowed time for filing a protest, the proposed activity shall be deemed to be authorized effective the day after the time allowed for protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request for authorization will be considered by the Commission.

Protests must comply with the requirements specified in section 157.205(e) of the Commission's regulations,³ and must be submitted by the protest deadline, which is August 5, 2024. A protest may also serve as a motion to intervene so long as the protestor states it also seeks to be an intervenor.

¹ 18 CFR 157.205.

² Persons include individuals, organizations, businesses, municipalities, and other entities. 18 CFR 385.102(d).

³ 18 CFR 157.205(e).

Interventions

Any person has the option to file a motion to intervene in this proceeding. Only intervenors have the right to request rehearing of Commission orders issued in this proceeding and to subsequently challenge the Commission's orders in the U.S. Circuit Courts of Appeal.

To intervene, you must submit a motion to intervene to the Commission in accordance with Rule 214 of the Commission's Rules of Practice and Procedure⁴ and the regulations under the NGA⁵ by the intervention deadline for the project, which is August 5, 2024. As described further in Rule 214, your motion to intervene must state, to the extent known, your position regarding the proceeding, as well as your interest in the proceeding. For an individual, this could include your status as a landowner, ratepayer, resident of an impacted community, or recreationist. You do not need to have property directly impacted by the project in order to intervene. For more information about motions to intervene, refer to the FERC website at <https://www.ferc.gov/resources/guides/how-to/intervene.asp>.

All timely, unopposed motions to intervene are automatically granted by operation of Rule 214(c)(1). Motions to intervene that are filed after the intervention deadline are untimely and may be denied. Any late-filed motion to intervene must show good cause for being late and must explain why the time limitation should be waived and provide justification by reference to factors set forth in Rule 214(d) of the Commission's Rules and Regulations. A person obtaining party status will be placed on the service list maintained by the Secretary of the Commission and will receive copies (paper or electronic) of all documents filed by the applicant and by all other parties.

Comments

Any person wishing to comment on the project may do so. The Commission considers all comments received about the project in determining the appropriate action to be taken. To ensure that your comments are timely and properly recorded, please submit your comments on or before August 5, 2024. The filing of a comment alone will not serve to make the filer a party to the proceeding. To become a party, you must intervene in the proceeding.

⁴ 18 CFR 385.214.

⁵ 18 CFR 157.10.

How To File Protests, Interventions, and Comments

There are two ways to submit protests, motions to intervene, and comments. In both instances, please reference the Project docket number CP24-473-000 in your submission.

(1) You may file your protest, motion to intervene, and comments by using the Commission's eFiling feature, which is located on the Commission's website (www.ferc.gov) under the link to Documents and Filings. New eFiling users must first create an account by clicking on "eRegister." You will be asked to select the type of filing you are making; first select "General" and then select "Protest", "Intervention", or "Comment on a Filing"; or⁶

(2) You can file a paper copy of your submission by mailing it to the address below. Your submission must reference the Project docket number CP24-473-000.

To file via USPS: Debbie-Anne A. Reese, Acting Secretary, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426

To file via any other method: Debbie-Anne A. Reese, Acting Secretary, Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, Maryland 20852

The Commission encourages electronic filing of submissions (option 1 above) and has eFiling staff available to assist you at (202) 502-8258 or FercOnlineSupport@ferc.gov.

Protests and motions to intervene must be served on the applicant either by mail or email (with a link to the document) at: Joseph Moake, Director, Regulatory Project Strategy, Cheniere Corpus Christi Pipeline, L.P., 845 Texas Avenue, Suite 1250, Houston, Texas 77002 or by joseph.moake@cheniere.com. Any subsequent submissions by an intervenor must be served on the applicant and all other parties to the proceeding. Contact information for parties can be downloaded from the service list at the eService link on FERC Online.

Tracking the Proceeding

Throughout the proceeding, additional information about the project will be available from the Commission's Office of External Affairs, at (866) 208-FERC, or on the FERC website at www.ferc.gov using the "eLibrary" link

as described above. The eLibrary link also provides access to the texts of all formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. For more information and to register, go to www.ferc.gov/docs-filing/esubscription.asp.

Dated: June 5, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024-12759 Filed 6-10-24; 8:45 am]

BILLING CODE 6717-01-P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER24-2139-000]

Capon Bridge Solar, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Capon Bridge Solar, LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is June 25, 2024.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at <http://www.ferc.gov>. To facilitate electronic service, persons with internet access

who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (<http://www.ferc.gov>). From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. Email the Public Reference Room at public.referenceroom@ferc.gov.

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: June 5, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024-12754 Filed 6-10-24; 8:45 am]

BILLING CODE 6717-01-P

⁶ Additionally, you may file your comments electronically by using the eComment feature, which is located on the Commission's website at www.ferc.gov under the link to Documents and Filings. Using eComment is an easy method for interested persons to submit brief, text-only comments on a project.

DEPARTMENT OF ENERGY**Federal Energy Regulatory Commission****[Docket No. ER24–2183–000]****Big Rock ESS Assets LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization**

This is a supplemental notice in the above-referenced proceeding of Big Rock ESS Assets LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is June 25, 2024.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at <http://www.ferc.gov>. To facilitate electronic service, persons with internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all

interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (<http://www.ferc.gov>). From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at public.referenceroom@ferc.gov.

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: June 5, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

[FR Doc. 2024–12757 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY**Federal Energy Regulatory Commission****[Project No. 4678–000]****New York Power Authority; Notice of Authorization for Continued Project Operation**

The license for the Crescent Hydroelectric Project No. 4678 was issued for a period ending May 31, 2024.

Section 15(a)(1) of the FPA, 16 U.S.C. 808(a)(1), requires the Commission, at

the expiration of a license term, to issue from year-to-year an annual license to the then licensee(s) under the terms and conditions of the prior license until a new license is issued, or the project is otherwise disposed of as provided in section 15 or any other applicable section of the FPA. If the project's prior license waived the applicability of section 15 of the FPA, then, based on section 9(b) of the Administrative Procedure Act, 5 U.S.C. 558(c), and as set forth at 18 CFR 16.21(a), if the licensee of such project has filed an application for a subsequent license, the licensee may continue to operate the project in accordance with the terms and conditions of the license after the minor or minor part license expires, until the Commission acts on its application. If the licensee of such a project has not filed an application for a subsequent license, then it may be required, pursuant to 18 CFR 16.21(b), to continue project operations until the Commission issues someone else a license for the project or otherwise orders disposition of the project.

If the project is subject to section 15 of the FPA, notice is hereby given that an annual license for Project No. 4678 is issued to the New York Power Authority for a period effective June 1, 2024, through May 31, 2025, or until the issuance of a new license for the project or other disposition under the FPA, whichever comes first.

If issuance of a new license (or other disposition) does not take place on or before May 31, 2025, notice is hereby given that, pursuant to 18 CFR 16.18(c), an annual license under section 15(a)(1) of the FPA is renewed automatically without further order or notice by the Commission, unless the Commission orders otherwise.

If the project is not subject to section 15 of the FPA, notice is hereby given that New York Power Authority is authorized to continue operation of the Crescent Hydroelectric Project under the terms and conditions of the prior license until the issuance of a subsequent license for the project or other disposition under the FPA, whichever comes first.

Dated: June 5, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

[FR Doc. 2024–12750 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY**Federal Energy Regulatory Commission****Notice of Staff Attendance at North American Electric Reliability Corporation Joint Reliability and Security Technical Committee and Standards Committee Meetings; Standard Team Drafting Meeting; Inverter-Based Resource Performance Subcommittee Meeting; and U.S. Department of Energy's Interconnection Innovation Exchange Forum for the Implementation of Reliability Standards for Transmission Meeting**

The Federal Energy Regulatory Commission hereby gives notice that members of the Commission and/or Commission staff may attend the following meetings:

North American Electric Reliability Corporation: Reliability and Security Technical Committee Meeting:
Amazon Headquarters, SEA51 Mayday Building, 1220 Howell Street, Seattle, WA 98101
June 11, 2024 | 8:00 a.m.–5:00 p.m. Pacific

Further information regarding this meeting and how to join remotely may be found at: https://www.nerc.com/comm/RSTC/AgendaHighlightsandMinutes/RSTC_Agenda_June_11_2024.pdf.

North American Electric Reliability Corporation: Standards Committee Process Subcommittee Meeting:
Amazon Headquarters, SEA51 Mayday Building, 1220 Howell Street, Seattle, WA 98101
June 11, 2024 | 12:00 p.m.–1:30 p.m. Pacific

Further information regarding this meeting and how to join remotely may be found at: https://www.nerc.com/comm/SC/Standards%20Committee%20Process%20Subcommittee%20SCPS/scps_agenda_package_june_11_2024.pdf.

North American Electric Reliability Corporation: Project Management and Oversight Subcommittee Meeting:
Amazon Headquarters, SEA51 Mayday Building, 1220 Howell Street, Seattle, WA 98101
June 11, 2024 | 2:00 p.m.–4:00 p.m. Pacific

Further information regarding this meeting and how to join remotely may be found at: <https://nerc.webex.com/wbxmjs/join/service/sites/nerc/meeting/download/63197D3E66D57F2AE0533D84FC0A2A87>.

North American Electric Reliability Corporation: Reliability and Security

Technical Committee Informational Session:

Amazon Headquarters, SEA51 Mayday Building, 1220 Howell Street, Seattle, WA 98101
June 12, 2024 | 8:00 a.m.–12:00 p.m. Pacific

Further information regarding this meeting and how to join remotely may be found at: https://www.nerc.com/comm/RSTC/AgendaHighlightsandMinutes/RSTC_Agenda_June_12_2024.pdf.

North American Electric Reliability Corporation: Standards Committee Meeting:
Amazon Headquarters, SEA51 Mayday Building, 1220 Howell Street, Seattle, WA 98101
June 12, 2024 | 9:00 a.m.–12:00 p.m. Pacific

Further information regarding this meeting and how to join remotely may be found at: https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_Agenda_Package_June_12_2024.pdf.

North American Electric Reliability Corporation: Joint Reliability and Security Technical Committee and Standards Committee Informational Session:
Amazon Headquarters, SEA51 Mayday Building, 1220 Howell Street, Seattle, WA 98101
June 12, 2024 | 1:30 p.m.–4:30 p.m. Pacific

Further information regarding this meeting and how to join remotely may be found at: https://www.nerc.com/comm/RSTC/AgendaHighlightsandMinutes/Joint_RSTC_SC_Agenda_Package_June_12_2024.pdf.

North American Electric Reliability Corporation: Project 2021–04 Modifications to PRC–002—Phase II Standard Drafting Team Meeting:
NERC DC Office, 1401 H St. NW, Suite 410, Conference Room 419, Washington, DC 20005
June 20, 2024 | 10:00 a.m.–5:00 p.m. Eastern

June 21, 2024 | 8:30 a.m.–12:00 p.m. Eastern

Further information regarding this meeting and how to join remotely may be found at: <https://www.nerc.com/pa/Stand/Lists/stand/DispForm.aspx?ID=2363>.

North American Electric Reliability Corporation: Inverter-Based Resource Performance Subcommittee Meeting, WebEx
June 20, 2024 | 1:00 p.m.–4:00 p.m. Eastern

Further information regarding this meeting and how to join remotely may

be found at: <https://www.nerc.com/pa/RAPA/Lists/RAPA/DispForm.aspx?ID=657>.

U.S. Department of Energy's (DOE) Interconnection Innovation e-Xchange (i2X) Forum for the Implementation of Reliability Standards for Transmission (FIRST) Meeting, Zoom:
June 25, 2024 | 11:00 a.m.–1:00 p.m. Eastern

Further information regarding this meeting and how to register may be found at: <https://www.zoomgov.com/meeting/register/vJltceuoRtSiErIC-HInpPbWuTUtrYQAuoM#/registration>.

The discussions at the meetings, which are open to the public, may address matters at issue in the following Commission proceedings:

Docket No. RR24–2–000—North American Electric Reliability Corporation

For further information, please contact Leigh Anne Faugust (202) 502–6396 or leigh.faugust@ferc.gov.

Dated: June 5, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

[FR Doc. 2024–12753 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY**Federal Energy Regulatory Commission**

[Docket No. EF24–6–000]

Western Area Power Administration; Notice of Filing

Take notice that on May 31, 2024, Western Area Power Administration submitted a tariff filing per 10 CFR 903.23: RMR CRSPLAPWACM_WAPA214–20240529 to be effective 10/1/2024.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission strongly encourages electronic filings of comments, protests and interventions in lieu of paper using

the “eFiling” link at <http://www.ferc.gov>. Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

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.

Comment Date: 5:00 p.m. Eastern Time on July 1, 2024.

Dated: June 4, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

[FR Doc. 2024–12679 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 4679–000]

New York Power Authority; Notice of Authorization for Continued Project Operation

The license for the Vischer Ferry Hydroelectric Project No. 4679 was issued for a period ending May 31, 2024.

Section 15(a)(1) of the FPA, 16 U.S.C. 808(a)(1), requires the Commission, at the expiration of a license term, to issue from year-to-year an annual license to the then licensee(s) under the terms and conditions of the prior license until a new license is issued, or the project is otherwise disposed of as provided in section 15 or any other applicable section of the FPA. If the project’s prior license waived the applicability of section 15 of the FPA, then, based on section 9(b) of the Administrative Procedure Act, 5 U.S.C. 558(c), and as set forth at 18 CFR 16.21(a), if the licensee of such project has filed an application for a subsequent license, the licensee may continue to operate the project in accordance with the terms

and conditions of the license after the minor or minor part license expires, until the Commission acts on its application. If the licensee of such a project has not filed an application for a subsequent license, then it may be required, pursuant to 18 CFR 16.21(b), to continue project operations until the Commission issues someone else a license for the project or otherwise orders disposition of the project.

If the project is subject to section 15 of the FPA, notice is hereby given that an annual license for Project No. 4679 is issued to the New York Power Authority for a period effective June 1, 2024, through May 31, 2025, or until the issuance of a new license for the project or other disposition under the FPA, whichever comes first.

If issuance of a new license (or other disposition) does not take place on or before May 31, 2025, notice is hereby given that, pursuant to 18 CFR 16.18(c), an annual license under section 15(a)(1) of the FPA is renewed automatically without further order or notice by the Commission, unless the Commission orders otherwise.

If the project is not subject to section 15 of the FPA, notice is hereby given that New York Power Authority is authorized to continue operation of the Vischer Ferry Hydroelectric Project under the terms and conditions of the prior license until the issuance of a subsequent license for the project or other disposition under the FPA, whichever comes first.

Dated: June 5, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

[FR Doc. 2024–12752 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 14861–002]

FFP Project 101, LLC; Notice of Meeting

a. *Project Name and Number:* Goldendale Energy Storage Project No. 14861–002.

b. *Applicant:* FFP Project 101, LLC.

c. *Date and Time of Meeting:* Monday, June 17, 2024 from 10:00 a.m. to 12:00 p.m. Pacific Standard Time (1:00 p.m. to 3:00 p.m. Eastern Standard Time).

d. *FERC Contact:* Michael Tust, (202) 502–6522, michael.tust@ferc.gov.

e. *Purpose of Meeting:* Commission staff will hold a meeting with representatives from the Washington

State Historic Preservation Office (Washington SHPO), Advisory Council on Historic Preservation (Advisory Council), and affected Tribes to discuss revisions to Commission staff’s draft Programmatic Agreement and discuss mitigation for unavoidable adverse impacts to cultural resources for the proposed Goldendale Energy Storage Project pursuant to section 106 of the National Historic Preservation Act. The meeting will be held virtually via Microsoft Teams.

f. Intervenor in the referenced proceeding may attend the meeting as observers; however, participation will be limited to representatives from the Washington SHPO, Advisory Council, Tribes, and Commission staff. If meeting attendees decide to disclose information about a specific location which could create a risk or harm to an archaeological site or Native American cultural resource, attendees other than Washington SHPO, Advisory Council, Tribal representatives and Commission staff will be excused for that portion of the meeting.

A summary of the meeting will be placed in the public record of this proceeding. As appropriate, the meeting summary will include both a public, redacted version that excludes any information about the specific location of the archeological site or Native American cultural resource and an unredacted privileged version. Intervenor planning to attend the meeting should notify Michael Tust at (202) 502–6522 or michael.tust@ferc.gov by Friday, June 14, 2024 to RSVP and to receive specific instructions for logging in to the meeting.

Dated: June 5, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

[FR Doc. 2024–12758 Filed 6–10–24; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER24–2179–000]

Bayou Galion Solar Project, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Bayou Galion Solar Project, LLC’s application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for

blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is June 24, 2024.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at <http://www.ferc.gov>. To facilitate electronic service, persons with internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (<http://www.ferc.gov>). From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. Email the

Public Reference Room at public.referenceroom@ferc.gov.

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: June 4, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

[FR Doc. 2024-12678 Filed 6-10-24; 8:45 am]

BILLING CODE 6717-01-P

ENVIRONMENTAL PROTECTION AGENCY

[CERCLA-04-2024-7011; FRL-11975-01-R4]

Aberdeen Contaminated Groundwater Site, Aberdeen, North Carolina; Cashout Settlement Agreement

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of cashout settlement agreement.

SUMMARY: Under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), the United States Environmental Protection Agency has entered into a settlement with LPC Holdings, Inc., concerning the Aberdeen Contaminated Groundwater Superfund Site located in Aberdeen, North Carolina. The settlement addresses recovery of CERCLA costs for cleanup response actions performed at the Site and costs incurred by EPA.

DATES: The Agency will consider public comments on the proposed settlement until July 11, 2024. The Agency will consider all comments received and may modify or withdraw its consent to the proposed settlement if comments received disclose facts or considerations which indicate that the proposed settlement is inappropriate, improper, or inadequate.

ADDRESSES: Copies of the settlement are available from the Agency by contacting Ms. Paula V. Painter, Program Analyst, using the contact information provided in this notice. Comments may also be submitted by referencing the Site's

name through one of the following methods:

Internet: <https://www.epa.gov/aboutepa/about-epa-region-4-southeast#r4-public-notices>
Email: Painter.Paula@epa.gov

FOR FURTHER INFORMATION CONTACT: Paula V. Painter at 404/562-8887.

Maurice Horsey,

Chief, Enforcement Branch, Superfund & Emergency Management Division.

[FR Doc. 2024-12722 Filed 6-10-24; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

[CERCLA-04-2024-7002- et al.; FRL-11984-01-R4]

Bennett Landfill Fire Superfund Site, Chester, South Carolina; Proposed Settlements

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed settlements.

SUMMARY: Under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), the United States Environmental Protection Agency is proposing to enter into individual settlements with seven additional parties concerning the Bennett Landfill Fire Site located in Chester, South Carolina. The proposed settlements address recovery of EPA's costs incurred performing a CERCLA cleanup at the Site.

DATES: The Agency will consider public comments on the proposed settlements until July 11, 2024. The Agency will consider all comments received and may modify or withdraw its consent to the proposed settlements if comments received disclose facts or considerations which indicate that the proposed settlements are inappropriate, improper, or inadequate.

ADDRESSES: Copies of the proposed settlements are available from the Agency by contacting Ms. Paula V. Painter, Program Analyst, using the contact information provided in this notice. Comments may also be submitted by referencing the Site's name through one of the following methods:

Internet: <https://www.epa.gov/aboutepa/about-epa-region-4-southeast#r4-public-notices>
Email: Painter.Paula@epa.gov

FOR FURTHER INFORMATION CONTACT: Paula V. Painter at 404/562-8887.

SUPPLEMENTARY INFORMATION: The individual proposed settlements are as

follows: Clear Site Industrial, LLC, 04–2024–7002, Spartanburg Regional Healthcare Services District, Inc., 04–2024–7004, Johns Manville, 04–2024–7003, International Paper Co., 04–2024–7007, Durham Timber, Inc. 04–2024–7006, Kohler Co., 04–2024–7009, Bellsouth Telecommunications, LLC, 04–2024–7008.

Maurice Horsey,

*Branch Manager, Enforcement Branch,
Superfund & Emergency Management
Division.*

[FR Doc. 2024–12721 Filed 6–10–24; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

**[EPA–HQ–OAR–2023–0014; FRL–11991–01–
OAR; SAN 11991]**

Clean Air Act Advisory Committee (CAAAC): Notice of Meeting

AGENCY: Environmental Protection
Agency (EPA).

ACTION: Notice of meeting.

SUMMARY: Pursuant to the Federal Advisory Committee Act (FACA), the Environmental Protection Agency (EPA) is announcing a public meeting of the Clean Air Act Advisory Committee (CAAAC). The EPA renewed the CAAAC charter on October 31, 2022, to provide independent advice and counsel to EPA on economic, environmental, technical, scientific and enforcement policy issues associated with implementation of the Clean Air Act of 1990.

DATES: The CAAAC will hold its next virtual public meeting on Tuesday, June 25, 2024, from 1:00 p.m. to 3:00 p.m. (EDT). Members of the public may register to listen to the meeting or provide comments, by emailing caaac@epa.gov by 5:00 p.m. (EST) June 24, 2024.

FOR FURTHER INFORMATION CONTACT:

Lorraine Reddick, Designated Federal Officer, Clean Air Act Advisory Committee (6103A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460; telephone number: 202–564–1293; email address: redrick.lorraine@epa.gov. Additional information about this meeting, the CAAAC, and its subcommittees and workgroups can be found on the CAAAC website: <http://www.epa.gov/caaac>.

SUPPLEMENTARY INFORMATION: Pursuant to 5 U.S.C. App. 2 section 10(a)(2), notice is hereby given that the Clean Air Act Advisory Committee will hold its next virtual public meeting on Tuesday,

June 25, 2024, from 1:00 p.m. to 3:00 p.m. (EDT).

The committee agenda and any documents prepared for the meeting will be publicly available on the CAAAC website at <http://www.epa.gov/caaac> prior to the meeting. Thereafter, these documents, together with CAAAC meeting minutes, will be available on the CAAAC website or by contacting the Office of Air and Radiation Docket and requesting information under docket EPA–HQ–OAR–2023–0014. The docket office can be reached by email at: a-and-r-Docket@epa.gov or FAX: 202–566–9744.

For information on access or services for individuals with disabilities, please contact Lorraine Reddick at redrick.lorraine@epa.gov, preferably at least 7 days prior to the meeting to give EPA as much time as possible to process your request.

Lorraine Reddick,

*Designated Federal Officer, Office of Air
Policy and Program Support.*

[FR Doc. 2024–12694 Filed 6–10–24; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL ACCOUNTING STANDARDS ADVISORY BOARD

Notice of Appointments Panel Meeting

AGENCY: Federal Accounting Standards
Advisory Board.

ACTION: Notice.

SUMMARY: Notice is hereby given that the Appointments Panel, a subcommittee of the Federal Accounting Standards Advisory Board (FASAB), will hold a meeting on June 28, 2024. The Appointments Panel makes recommendations regarding appointments for non-Federal member positions.

FOR FURTHER INFORMATION CONTACT: Ms. Monica R. Valentine, Executive Director, 441 G Street NW, Suite 1155, Washington, DC 20548, or call (202) 512–7350.

SUPPLEMENTARY INFORMATION: The meetings are closed to the public. The reason for the closure is that matters covered by 5 U.S.C. 552b(c)(2) and (6) will be discussed. Any such discussions will involve matters that relate solely to internal personnel rules and practices of the sponsor agencies and the disclosure of information of a personal nature where disclosure would constitute a clearly unwarranted invasion of personal privacy.

Pursuant to section 10(d) of the Federal Advisory Committee Act (FACA), 5 U.S.C. 1009(d), portions of

advisory committee meetings may be closed to the public where the head of the agency to which the advisory committee reports determines that such portion of such meeting may be closed to the public in accordance with subsection (c) of section 552b of title 5, United States Code. The determination shall be in writing and shall contain the reasons for the determination. A determination has been made in writing by the U.S. Government Accountability Office, the U.S. Department of the Treasury, and the Office of Management and Budget, as required by section 10(d) of FACA, that such portions of the meetings may be closed to the public in accordance with subsection (c) of section 552b of title 5, United States Code.

Authority: 31 U.S.C. 3511(d); Federal Advisory Committee Act, 5 U.S.C. 1001–1014).

Dated: June 5, 2024.

Monica R. Valentine,
Executive Director.

[FR Doc. 2024–12697 Filed 6–10–24; 8:45 am]

BILLING CODE 1610–02–P

FEDERAL MARITIME COMMISSION **[DOCKET NO. 24–23]**

Samsung Electronics America, Inc., Complainant v. HMM Co., Ltd. f/k/a Hyundai Merchant Marine Co., Ltd., Respondent. Notice of Filing of Complaint and Assignment

Served: June 5, 2024.

Notice is given that a complaint has been filed with the Federal Maritime Commission (the “Commission”) by Samsung Electronics America, Inc. (the “Complainant”) against HMM Co., Ltd. f/k/a Hyundai Merchant Marine Co., Ltd. (the “Respondent”). Complainant states that the Commission has subject matter jurisdiction over the complaint pursuant to the Shipping Act of 1984, as amended, 46 U.S.C. 40101 *et seq.* and personal jurisdiction over the Respondent as a common carrier and vessel-operating ocean common carrier, as these terms are defined in 46 U.S.C. 40102.

Complainant is a corporation organized and existing under the laws of the State of New York with a principal place of business in Ridgefield Park, New Jersey.

Complainant identifies Respondent as a global ocean carrier with its corporate office in Seoul, Korea, that does business in the United States through HMM America Shipping Agency, Inc. with its principal place of business in Ridgefield Park, New Jersey.

Complainant alleges that Respondent violated 46 U.S.C. 41102(c) and (d), and 41104(a)(3), (10), (14), and (15); and 46 CFR 545.4 and 545.5. Complainant alleges these violations arose from assessment of detention and demurrage charges on “store door” shipments for reasons not within the control of Complainant, issuance of invoices for detention and demurrage charges that did not contain the information required, threats to refuse and refusals of available cargo space accommodation, and other acts and omissions of the Respondents.

An answer to the complaint must be filed with the Commission within 25 days after the date of service.

The full text of the complaint can be found in the Commission’s electronic Reading Room at <https://www2.fmc.gov/readingroom/proceeding/24-23/>. This proceeding has been assigned to the Office of Administrative Law Judges. The initial decision of the presiding judge shall be issued by June 5, 2025, and the final decision of the Commission shall be issued by December 19, 2025.

David Eng,
Secretary.

[FR Doc. 2024-12719 Filed 6-10-24; 8:45 am]

BILLING CODE 6730-02-P

GENERAL SERVICES ADMINISTRATION

[Notice—PBS—2024-06; Docket No. 2024-0002; Sequence No. 27]

Notice of Availability for the Record of Decision on the Supplemental Environmental Impact Statement for the International Falls Land Port of Entry Modernization and Expansion Project in International Falls, Minnesota

AGENCY: Great Lakes Region 5, Public Buildings Service (PBS), General Services Administration (GSA).

ACTION: Notice.

SUMMARY: GSA issued a Record of Decision (ROD) on the Supplemental Environmental Impact Statement (SEIS) for the International Falls Land Port of Entry (LPOE) Modernization and Expansion Project in International Falls, Minnesota (MN), on May 30, 2024. The ROD was prepared in accordance with the National Environmental Policy Act (NEPA) of 1969, the Council on Environmental Quality Regulations, and the GSA PBS NEPA Desk Guide.

DATES: *Applicable:* Thursday, May 30, 2024.

ADDRESSES: The ROD may be found online at the following website: <https://www.gsa.gov/about-us/gsa-regions/region-5-great-lakes/buildings-and-facilities/minnesota/international-falls-land-port-of-entry>.

FOR FURTHER INFORMATION CONTACT: Michael Gonczar, NEPA Program Manager, GSA, at 312-810-2326, or via email to michael.gonczar@gsa.gov.

SUPPLEMENTARY INFORMATION:

Background

The International Falls LPOE is a port of entry for vehicles and pedestrians crossing the U.S.-Canada border between International Falls, MN and the town of Fort Frances, Ontario, Canada. The port is operated by the U.S. Department of Homeland Security’s Customs and Border Protection (CBP) and is a full-service, multi-modal facility where CBP officers inspect commercially owned vehicles (COVs), privately owned vehicles (POVs), and pedestrians.

The *International Falls LPOE Improvements Study Final EIS*, released in 2011, assessed the potential environmental impacts associated with the proposed action of replacing the International Falls LPOE with a new LPOE facility “to improve safety, security, and functionality.” A total of ten build alternatives were considered, and a preferred action alternative was identified in the 2011 Final EIS as best satisfying the purpose and need of the project with the least overall adverse impacts to the environment. The 2011 preferred alternative consisted of demolishing the existing building, constructing new facilities at the existing LPOE, and expanding the LPOE to meet the required space standards and increased security requirements of the Federal Inspection Services. The 2011 preferred alternative proposed to move the majority of the LPOE improvements and operations to an approximately 20-acre site southeast of the existing site. Since 2011, GSA identified changes to the project, which differed from the preferred alternative described in the 2011 EIS. As such, GSA prepared a Final SEIS to assess the potential impacts of project updates, which were not assessed in the 2011 EIS.

The purpose of the Proposed Action is for GSA to support CBP’s mission by bringing the International Falls LPOE operations in line with current land port design standards and operational requirements of CBP while addressing existing deficiencies identified with the ongoing port operations. In order to bring the International Falls LPOE

operations in line with CBP’s design standards and operational requirements, the Proposed Action is needed to (1) improve the capacity and functionality of the International Falls LPOE to meet future demand, while maintaining the capability to meet border security initiatives; (2) address spatial and layout constraints that lead to traffic congestion and safety issues for the employees and users of the LPOE; and (3) provide adequate space and facilities for the Federal agencies to accomplish their missions.

On December 9, 2022, GSA published a Notice of Intent for the SEIS and underwent a 35-day scoping period. A Draft SEIS and Draft Floodplain Assessment and Statement of Findings were issued over a 45-day public comment period on October 27, 2023; and a Final SEIS and Floodplain Assessment and Statement of Findings were issued over a 30-day waiting period on April 19, 2024.

Comments received, along with GSA’s responses, during the Final SEIS waiting period are provided in Appendix A and B of the ROD.

Preferred Alternative

GSA has chosen to implement Alternative 1: Full Build as defined in the Final SEIS (GSA, April 2024). This decision is based on the Final SEIS issued in April 2024; associated technical reports; comments from Federal and State agencies, stakeholders, members of the public, and elected officials; and miscellaneous resources contained in the administrative record.

Alternative 1 (Full Build) includes the project as generally assessed under the 2011 preferred alternative but modified by project updates. Similar to the 2011 preferred alternative, Alternative 1 proposed expansion area encompasses an approximately 20-acre area that stretches east from the LPOE along the Rainy River shoreline to an area just west of a U.S. Border Patrol Station and primarily bordered by State Route 11 (SR-11) on the south. Approximately 16 and 4 acres are owned by the Packing Corporation of America (PCA) and Recreational Land Development, LLC, respectively. Most of the LPOE functions will be relocated in the expanded portion of the parcel between the Rainy River and SR-11. A construction phasing plan will be developed during design and implemented during demolition and construction to ensure continuity of operations of the LPOE, as well as minimize disruptions to PCA and other neighboring operations.

To prepare the proposed expansion area for development, some existing utilities and PCA infrastructure will need to be accommodated in a new way, either within the LPOE via easements or moved off site to the west or south on PCA-owned land. Project changes have triggered the reconfiguration of some of the existing PCA operations on PCA lands and will require relocation of some infrastructure associated with PCA, the MD&W Railway, and OfficeMax. Relocation of utilities and infrastructure may be conducted by either GSA or PCA, depending on final acquisition negotiations. Actions taken by PCA are considered as connected actions to the Proposed Action.

Alternative 1 also considers the implementation of renewable energy technologies within the expanded and modernized LPOE. These technologies were not considered in the 2011 Final EIS but have since been proposed for inclusion in future site plans. Renewable technologies that may be incorporated into the facility design include solar and geothermal technologies, depending on the final design.

GSA is currently undergoing formal consultation with the State Historic Preservation Officer (SHPO) and consulting parties to follow coordination procedures as required under Section 106 of the National Historic Preservation Act. GSA intends on implementing and complying with all mitigation measures resulting from section 106 consultation as detailed in the ROD.

William Renner,

Director, Facilities Management and Services Programs Division, Great Lakes Region 5, U.S. General Services Administration.

[FR Doc. 2024-12700 Filed 6-10-24; 8:45 am]

BILLING CODE 6820-CF-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifiers: CMS-381 and CMS-R-38]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Centers for Medicare & Medicaid Services, Health and Human Services (HHS).

ACTION: Notice.

SUMMARY: The Centers for Medicare & Medicaid Services (CMS) is announcing

an opportunity for the public to comment on CMS' intention to collect information from the public. Under the Paperwork Reduction Act of 1995 (PRA), Federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension or reinstatement of an existing collection of information, and to allow a second opportunity for public comment on the notice. Interested persons are invited to send comments regarding the burden estimate or any other aspect of this collection of information, including the necessity and utility of the proposed information collection for the proper performance of the agency's functions, the accuracy of the estimated burden, ways to enhance the quality, utility, and clarity of the information to be collected, and the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

DATES: Comments on the collection(s) of information must be received by the OMB desk officer by July 11, 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.

To obtain copies of a supporting statement and any related forms for the proposed collection(s) summarized in this notice, please access the CMS PRA website by copying and pasting the following web address into your web browser: <https://www.cms.gov/Regulations-and-Guidance/Legislation/PaperworkReductionActof1995/PRA-Listing>.

FOR FURTHER INFORMATION CONTACT:

William Parham at (410) 786-4669.

SUPPLEMENTARY INFORMATION: Under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501-3520), Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. The term "collection of information" is defined in 44 U.S.C. 3502(3) and 5 CFR 1320.3(c) and includes agency requests or requirements that members of the public submit reports, keep records, or provide information to a third party. Section 3506(c)(2)(A) of the PRA (44 U.S.C. 3506(c)(2)(A)) requires Federal agencies to publish a 30-day notice in the

Federal Register concerning each proposed collection of information, including each proposed extension or reinstatement of an existing collection of information, before submitting the collection to OMB for approval. To comply with this requirement, CMS is publishing this notice that summarizes the following proposed collection(s) of information for public comment:

1. *Type of Information Collection* Request: Revision of a currently approved collection; *Title of Information Collection:* Identification of Extension Units of Medicare Approved Outpatient Physical Therapy/Outpatient Speech Pathology (OPT/OSP) Providers and Supporting Regulations; *Use:* Form CMS-381 was developed to ensure that each OPT/OSP extension location at which OPT/OSP providers furnish services, must be reported by the providers to the State Survey Agencies (SAs). Form CMS-381 is completed when: (1) new OPT/OSP providers enter the Medicare program; (2) when existing OPT/OSP providers delete or add a service, or close or add an extension location; or, (3) when existing OPT/OSP providers are recertified by the State Survey Agency every 6 years.

In 2022, CMS transitioned some of the certification processes to the Center for Program Integrity (CPI) and the Medicare Administrative Contractor (MAC). Prior to the transition, the CMS Survey Operations Group was involved in the processing of the extension location requests. As a result of the new processing instructions, CMS is now reconciling the Form CMS-381 with updates to the instructions.

Additionally, CMS has revised the Form CMS-381 to incorporate the initial enrollment of OPT/OSPs which was previously completed on the Form CMS-1856 (0938-0065). CMS has combined the forms into one form in order to further align with the transitioned processes and streamline the requests from the provider community. This change will decrease the burden on both the provider community as well as CMS.

Furthermore, this change will also allow for OPTs who wish to initially enroll in the Medicare program to submit an extension location request with the initial enrollment. The State Survey Agency or Accrediting Organization (for those OPTs requesting deemed status) will survey the extension location during the initial survey to verify compliance with the Medicare conditions. *Form Number:* CMS-381 (OMB control number: 0938-0273); *Frequency:* Occasionally; *Affected Public:* Private Sector; Business or other for-profit and not-for-profit institutions;

Number of Respondents: 506; *Total Annual Responses:* 506; *Total Annual Hours:* 253. (For policy questions regarding this collection contact Caecilia Andrews at 410-786-2190.)

2. *Type of Information Collection Request:* Reinstatement of a previously approved collection; *Title of Information Collection:* Conditions for Certification for Rural Health Clinics and Conditions for Coverage for Federally Qualified Health Centers in 42 CFR 491; *Use:* The Conditions for Medicare Certification (CfCs) for Rural Health Clinics (RHCs) are based on criteria prescribed in law and designed to ensure that each RHC has properly trained staff to provide appropriate care and to assure a safe physical environment for patients. The information collection requirements described herein are needed to implement the Medicare and Medicaid CfCs for a total of 5,349 RHCs. These requirements are similar in intent to standards developed by industry organizations such as the Joint Commission on Accreditation of Hospitals, and the National League of Nursing/American Public Association, and merely reflect accepted standards of management and care to which rural health clinics must adhere.

Federally Qualified Health Centers (FQHCs) are also subject to Conditions for Certification to participate in the Medicare and Medicaid programs. These health and safety standards are the foundation for improving quality and protecting the health and safety of Medicare and Medicaid beneficiaries. The information collection requirements described herein affect approximately 11,252 FQHCs. The current information collection requirements at 42 CFR 491.9(b) and 491.11 are applicable to both RHCs and FQHCs. *Form Number:* CMS-R-38 (OMB control number: 0938-0334); *Frequency:* Recordkeeping and Reporting—Annually; *Affected Public:* Business or other for-profits; *Number of Respondents:* 17,663; *Total Annual Responses:* 17,663; *Total Annual Hours:* 104,245. (For policy questions regarding this collection contact Claudia Molinar at 410-786-8445.)

William N. Parham, III,

Director, Division of Information Collections and Regulatory Impacts, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. 2024-12774 Filed 6-10-24; 8:45 am]

BILLING CODE 4120-01-P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA-2024-N-2332]

Emerging Drug Safety Technology Meetings; Program Announcement

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Center for Drug Evaluation and Research (CDER) within the Food and Drug Administration (FDA or we) is announcing a meeting program, the Emerging Drug Safety Technology Meeting (EDSTM) program. These meetings will be administered by staff in the newly established CDER Emerging Drug Safety Technology Program (EDSTP). EDSTMs provide applicants with an approved application and/or other relevant parties supporting industry's pharmacovigilance (PV) activities (e.g., academia, contract research organizations (CROs), pharmacovigilance vendors, software developers) who meet the eligibility and selection criteria for participation with an opportunity to meet with CDER staff to discuss their research, development, and use of Artificial Intelligence (AI) and other emerging technologies in PV. The goals of the meeting program in its initial phase are to facilitate mutual learning and discussion of the pharmaceutical industry's application of these technologies to PV, including efforts to validate and verify relevant models. While the EDSTP is specifically focused on the use of AI in PV for postmarket activities, it is part of CDER's multifaceted approach to enhance mutual learning of where and how specific innovations, such as AI, can best be used across the drug product life cycle.

DATES: Applicants and other relevant parties may submit meeting requests under the program beginning June 11, 2024.

ADDRESSES: For additional information about the EDSTM program, please refer to FDA's web page at <https://www.fda.gov/drugs/science-and-research-drugs/cder-emerging-drug-safety-technology-program-edstp>.

FOR FURTHER INFORMATION CONTACT:

Ricardo Hernandez, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, Silver Spring, MD 20993-0002, 240-402-9526, or email AIMLforDrugDevelopment@fda.hhs.gov with the subject line "EDSTM—General Inquiry".

SUPPLEMENTARY INFORMATION:

I. Background

The pharmaceutical industry is expanding its use of AI and other emerging technology across the drug product life cycle. FDA is interested in accelerating its understanding of the research, development, and use of AI and other emerging technology in the area of pharmacovigilance, including their performance characteristics. The EDSTM is a means by which applicants and other relevant parties who meet the eligibility and selection criteria for participation, can meet with CDER to share information about their use of AI and other emerging technology, and its potential application in PV, including efforts to validate and verify relevant models.

The goal of the EDSTM is to facilitate mutual learning and discussion on the opportunities and challenges with using such technologies in PV. If selected for a meeting, application holders and/or other relevant parties will meet with CDER staff to discuss their research, development, and/or use of AI and other emerging technologies in PV. FDA plans to leverage these learnings to help inform potential regulatory and policy approaches, within the use of emerging technology in PV. The EDSTM program is not an avenue to seek regulatory advice on compliance with pharmacovigilance regulations. Rather, we expect that the information gained during this program will help CDER consider providing regulatory advice on specific technologies to facilitate their adoption when appropriate. The discussions and background information submitted through the EDSTMs are nonbinding on both FDA and EDSTM requesters.

EDSTMs may be requested by applicants with at least one approved application regulated by CDER, including new drug applications, abbreviated new drug applications, or biologics license applications, and/or by other relevant parties supporting industry's PV activities (e.g., academia, CROs/PV vendors, software developers) who develop, leverage, or intend to leverage AI or other emerging technology that can be used to satisfy the postmarketing reporting requirements in 21 CFR 314.80, 314.98, and 600.80. Eligible parties, such as an applicant or an applicant's PV vendor, may request meetings separately or in partnership. Requests may be submitted on a rolling basis and will be reviewed quarterly each calendar year. Please refer to the EDSTM program web page for details on submission deadlines for quarterly review. CDER will select up to

nine participants whose submissions meet the eligibility and selection criteria in a 12-month period for the initial phase of the EDSTM.

FDA has a longstanding commitment to ensure medicines marketed in the United States are safe through continued surveillance and research following approval. In the postmarket setting, regulated industry is obligated to review all adverse drug experience information received or otherwise obtained and submit timely reports to FDA. Both industry and regulatory authorities face challenges with timely and efficient collection, processing, and evaluation of single and aggregate patient safety data compounded by ever-increasing case volumes. Advances in emerging technology have the potential to address some of these challenges by creating more efficiencies within a PV system. For example, early adopters of AI are leveraging these emerging technologies to automate fundamental tasks (e.g., adverse event intake, data entry, and processing) with the intention to drive down associated administrative burden and costs. These technologies can also make safety surveillance more efficient and effective by capturing, aggregating, and analyzing larger and more diverse data sets.

FDA recognizes industry’s interest in dialogue around AI capabilities that advance PV. Knowledge and awareness of emerging technology tools, such as AI, and how they are used to advance PV will help inform CDER’s regulatory approaches and policies. FDA expects that increased communication with industry and/or other relevant parties during EDSTMs will accelerate FDA’s understanding of how AI enabled tools are being used for PV, their associated risks and benefits, and barriers to implementation.

FDA has established an EDSTP website that includes EDSTM eligibility and selection criteria, instructions for submission of a meeting request, meeting request and package content descriptions, and submission timelines. The program’s website address is <https://www.fda.gov/drugs/science-and-research-drugs/cder-emerging-drug-safety-technology-program-edstp>.

II. Paperwork Reduction Act of 1995

Collections of information from fewer than 10 respondents within any 12-month period are not subject to the Paperwork Reduction Act of 1995 (PRA) (5 CFR 1320.3(c)(4)). For the initial phase of this program, FDA will request information from no more than nine sponsors. Initial requests from sponsors interested in participation in the program are not “information” in accordance with 5 CFR 1320.3(h)(1). Therefore, clearance by the Office of Management and Budget under the PRA is not required.

Dated: June 6, 2024.
Lauren K. Roth,
Associate Commissioner for Policy.
[FR Doc. 2024–12770 Filed 6–10–24; 8:45 am]
BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES
[Document Identifier: 0937–0191–60D]
Agency Information Collection Request; 60-Day Public Comment Request
AGENCY: Office of the Secretary, HHS.
ACTION: Notice.

SUMMARY: In compliance with the requirement of the Paperwork Reduction Act of 1995, the Office of the Secretary (OS), Department of Health and Human Services, is publishing the following summary of a proposed collection for public comment. The ICR is for extending the use of the approved information collection assigned OMB control number 0937–0191, which expires on June 30, 2024. Prior to submitting the ICR to OMB, OS seeks comments from the public regarding the burden estimate, below, or any other aspect of the ICR.

DATES: Comments on the ICR must be received on or before August 12, 2024.

ADDRESSES: Submit your comments to Sherrette.Funn@hhs.gov or by calling (202) 264–0041 and PRA@HHS.GOV.

FOR FURTHER INFORMATION CONTACT: When submitting comments or requesting information, please include the document identifier 0937–0191–60D

and project title for reference, to Sherrette A. Funn, email: Sherrette.Funn@hhs.gov, PRA@HHS.GOV or call (202) 264–0041 the Reports Clearance Officer.

SUPPLEMENTARY INFORMATION: Interested persons are invited to send comments regarding this burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the agency’s functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

Application Packets for Real Property for Public Health Purposes

Type of Collection: Reinstatement, with no change.
OMB No.: 0937–0191.
Abstract: The Office of Assistant Secretary for Administration, Program Support Center, Federal Real Property Assistance Program is requesting OMB approval on a previously approved information collection, 0937–0191. 40 U.S.C. 550 (the “Act”), as amended, provides authority to the Secretary of Health and Human Services to convey or lease surplus real property to States and their political subdivisions and instrumentalities, to tax-supported institutions, and to nonprofit institutions which (except for institutions which lease property to assist the homeless) have been held exempt from taxation under section 501(c)(3) of the 1954 Internal Revenue Code, and 501(c)(19) for veterans organizations, for public health and homeless assistance purposes. Transfers are made to transferees at little or no cost.

Type of respondent: Responses are dependent on when Federal surplus real property is made available and is desired by a respondent/applicant for acquisition. Likely respondents include State, local, or Tribal units of government or instrumentalities thereof, and not-for-profit organizations.

ANNUALIZED BURDEN HOUR TABLE

Forms (if necessary)	Respondents (if necessary)	Number of respondents	Number of responses per respondents	Average burden per response	Total burden hours
Applications for surplus Federal real property		10	1	200	2,000
Total		10	1	200	2,000

Sherrette A. Funn,

Paperwork Reduction Act Reports Clearance Officer, Office of the Secretary.

[FR Doc. 2024–12683 Filed 6–10–24; 8:45 am]

BILLING CODE 4150–04–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer Institute; Notice of Meeting

Pursuant to section 1009 of the Federal Advisory Committee Act, as amended, notice is hereby given of a meeting of the National Cancer Institute Council of Research Advocates.

The meeting will be held as a virtual meeting and will be open to the public as indicated below. Individuals who plan to view the virtual meeting and need special assistance or other reasonable accommodations to view the meeting, should notify the Contact Person listed below in advance of the meeting. The meeting can be accessed from the NIH Videocast at the following link: <https://videocast.nih.gov/>.

Name of Committee: National Cancer Institute Council of Research Advocates (NCRA).

Date: June 26, 2024.

Time: 12:00 p.m. to 3:00 p.m.

Agenda: Welcome and Chairwoman's Remarks, NCI Director's Update, NCI Updates, and Legislative Update.

Place: National Institutes of Health, Building 31, 9000 Rockville Pike, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Amy Williams, Director, NCI Office of Advocacy Relations, National Cancer Institute, NIH, 31 Center Drive, Building 31, Room 10A28, Bethesda, MD 20892, (301) 496–9723, william@mail.nih.gov.

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

Information is also available on the Institute's/Center's home page: <https://deainfo.nci.nih.gov/advisory/ncra/ncra.htm>, where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.392, Cancer Construction; 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control, National Institutes of Health, HHS)

Dated: June 6, 2024.

David W. Freeman,

Supervisory Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2024–12736 Filed 6–10–24; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; 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: Center for Scientific Review Special Emphasis Panel; Understanding Neurobiology of Aging and Neurodegeneration.

Date: July 9, 2024.

Time: 9:30 a.m. to 6:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892.

Meeting Format: Virtual Meeting.

Contact Person: Wei-Qin Zhao, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5181, MSC 7846, Bethesda, MD 20892–7846, 301–827–7238, zhaow@csr.nih.gov.

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member conflict: Topics on Biobehavioral Processes.

Date: July 9–10, 2024.

Time: 10:00 a.m. to 8:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Rockledge II, 6701 Rockledge Drive, Bethesda, MD 20892.

Meeting Format: Virtual Meeting.

Contact Person: Aruna K Behera, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4211, MSC 7814, Bethesda, MD 20892, (301) 435–6809, beheraak@csr.nih.gov.

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844,

93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: June 6, 2024.

David W. Freeman,

Supervisory Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2024–12734 Filed 6–10–24; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Alcohol Abuse and Alcoholism; 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 on Alcohol Abuse and Alcoholism Special Emphasis Panel; NIAAA Special Emphasis Panel for Member Conflict Applications.

Date: July 1, 2024.

Time: 1:00 p.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, National Institute on Alcohol Abuse and Alcoholism, 6700B Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Luis Espinoza, Ph.D., Scientific Review Officer, Extramural Project Review Branch, Office of Extramural Activities, National Institute on Alcohol Abuse and Alcoholism, National Institutes of Health, 6700B Rockledge Drive, Room 2109, Bethesda, MD 20892, (301) 443–8599, espinozala@mail.nih.gov.

Name of Committee: National Institute on Alcohol Abuse and Alcoholism Special Emphasis Panel; NIAAA Fellowship Review Panel.

Date: July 9, 2024.

Time: 9:00 a.m. to 7:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, National Institute on Alcohol Abuse and Alcoholism, 6700B Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Luis Espinoza, Ph.D., Scientific Review Officer, Extramural Project Review Branch, Office of Extramural Activities, National Institute on Alcohol

Abuse and Alcoholism, National Institutes of Health, 6700B Rockledge Drive, Room 2109, Bethesda, MD 20892, (301) 443-8599, espinozala@mail.nih.gov.

Name of Committee: National Institute on Alcohol Abuse and Alcoholism Special Emphasis Panel; RFA AA-24-004 and 005—Limited Competition: Alcohol-associated Hepatitis Clinical Network—Integrated Treatment Clinical Trials.

Date: July 19, 2024.

Time: 11:00 a.m. to 2:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, National Institute on Alcohol Abuse and Alcoholism, 6700B Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Ranga Srinivas, Ph.D., Chief, Extramural Project Review Branch, National Institute on Alcohol Abuse and Alcoholism, National Institutes of Health, 6700B Rockledge Drive, Room 2114, Bethesda, MD 20892, (301) 451-2067, srinivar@mail.nih.gov.

Name of Committee: National Institute on Alcohol Abuse and Alcoholism Special Emphasis Panel; RFA-AA-23-004—Comprehensive Alcohol-HIV/AIDS Research Center (P60 Clinical Trial Optional).

Date: July 23-24, 2024.

Time: 10:00 a.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, National Institute on Alcohol Abuse and Alcoholism, 6700B Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Ranga Srinivas, Ph.D., Chief, Extramural Project Review Branch, National Institute on Alcohol Abuse and Alcoholism, National Institutes of Health, 6700B Rockledge Drive, Room 2114, Bethesda, MD 20892, (301) 451-2067, srinivar@mail.nih.gov.

Name of Committee: National Institute on Alcohol Abuse and Alcoholism Special Emphasis Panel; RFA AA-24-002 High-Throughput Screening Platform for Discovery of and PAR-22-103 Investigational New Drug (IND)-enabling and Early-Stage Development of Medications to Treat Alcohol Use disorder and Alcohol-Associated Organ Damage (UT1/UT2)

Date: July 25, 2024.

Time: 11:00 a.m. to 4:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, National Institute on Alcohol Abuse and Alcoholism, 6700B Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Luis Espinoza, Ph.D., Scientific Review Officer, Extramural Project Review Branch, Office of Extramural Activities, National Institute on Alcohol Abuse and Alcoholism, National Institutes of Health, 6700B Rockledge Drive, Room 2109, Bethesda, MD 20892, (301) 443-8599, espinozala@mail.nih.gov.

(Catalogue of Federal Domestic Assistance Program Nos. 93.273, Alcohol Research Programs, National Institutes of Health, HHS)

Dated: June 6, 2024.

David W Freeman,

Supervisory Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2024-12733 Filed 6-10-24; 8:45 am]

BILLING CODE 4140-01-P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR-7084-N-04]

60-Day Notice of Proposed Information Collection: Semi-Annual Labor Standards Enforcement Report—Local Contracting Agencies (HUD Program); OMB Control No.: 2501-0019

AGENCY: Office of Field Policy and Management, Housing and Urban Development (HUD).

ACTION: Notice.

SUMMARY: HUD is seeking approval from the Office of Management and Budget (OMB) for the information collection described below. In accordance with the Paperwork Reduction Act, HUD is requesting comment from all interested parties on the proposed collection of information. The purpose of this notice is to allow for 60 days of public comment.

DATES: *Comments Due Date:* August 12, 2024.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Written comments and recommendations for the proposed information collection can be sent within 60 days of publication of this notice to www.reginfo.gov/public/do/PRAMain. Find this particular information collection by selecting “Currently under 60-day Review—Open for Public Comments” or by using the search function. Interested persons are also invited to submit comments regarding this proposal and comments should refer to the proposal by name and/or OMB Control Number and should be sent to: Jennifer A. Dupont, Program Analyst, Office of Field Policy and Management, Department of Housing and Urban Development, 40 Marietta Street, 10th Floor, Atlanta, GA 30303 or the number (678) 732-2034 this is not a toll free number or email at Jennifer.A.Dupont@hud.gov for a copy of the proposed forms or other available information.

FOR FURTHER INFORMATION CONTACT: Colette Pollards, Reports Management Officer, QDAM, Department of Housing and Urban Development, 451 7th Street SW, Washington, DC 20410, telephone (202) 402-3400 (this is not a toll free number) or email Colette Pollard at

Colette.Pollard@hud.gov for copies of the proposed forms and other available information. HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech or communication disabilities. To learn more about how to make an accessible telephone call, please visit <https://www.fcc.gov/consumers/guides/telecommunications-relay-service-trs>.

SUPPLEMENTARY INFORMATION: The Department is submitting the proposed information collection to OMB for review, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 35, as amended).

This Notice is soliciting comments from members of the public and affected agencies concerning the proposed collection of information to: (1) Evaluate whether the proposed collection is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (2) Evaluate the accuracy of the agency’s estimate of the burden of the proposed collection of information; (3) Enhance the quality, utility, and clarity of the information to be collected; and (4) Minimize the burden of the collection of information on those who are to respond; including the use of appropriate automated collection techniques or other forms of information technology, *e.g.*, permitting electronic submission of responses.

This Notice also lists the following information:

Title of Information Collection: Semi-Annual Labor Standards Enforcement Report—Local Contracting Agencies (HUD Programs).

OMB Control Number, if applicable: 2501-0019.

Description of the need for the information and proposed use: The Department of Labor (DOL) requires all Federal agencies administering programs subject to Davis-Bacon wage requirements covered by 29 CFR 5.7(b) to submit a semi-annual report of all new covered contracts/projects and all enforcement activities during the six-month reporting period. For HUD to comply, HUD collects data from state and local agencies that administer HUD-assisted programs subject to Davis-Bacon requirements. HUD requires these agencies to complete and submit a Semi-annual Labor Standards Enforcement Report every six months. Respondents and HUD must retain a copy of the Semi-annual Labor Standards Enforcement Report files at least three years.

Agency form numbers, if applicable: HUD FORM 4710.

Estimation of the total numbers of respondents, frequency of response, and hours needed to prepare the information collection including number of hours of response:

Information collection	Number of respondents	Frequency of response	Responses per annum	Burden hour per response	Annual burden hours	Hourly cost per response	Annual cost
HUD 4710 Semi-Annual Labor Standards Enforcement Report—Local Contracting Agencies (HUD Programs)	4,565	2	9,130	1.0	9,130	\$48.69	\$444,539.70
HUD 4710 Semi-Annual Labor Standards Enforcement Report—Local Contracting Agencies (HUD Programs) /	0	0	0	0	0	0	0.00
Total	4,565	2	9,130	1.0	9,130	48.69	444,539.70

Authority: The Paperwork Reduction Act of 1995, 44 U.S.C. chapter 35, as amended.

Christopher D. Taylor,

Director, Field Policy and Management.

[FR Doc. 2024–12729 Filed 6–10–24; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[BLM HQ MO4500180135; OMB Control No. 1004–0204]

Agency Information Collection Activities; Bureau of Land Management Resource Advisory Council Application

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of information collection; request for comment.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, the Bureau of Land Management (BLM) is proposing to renew an information collection.

DATES: Interested persons are invited to submit comments on or before August 12, 2024.

ADDRESSES: Send your written comments on this information collection request (ICR) by mail to Darrin King, Information Collection Clearance Officer, U.S. Department of the Interior, Bureau of Land Management, Attention PRA Office, 440 W 200 S #500, Salt Lake City, UT 84101; or by email to BLM_HQ_PRA_Comments@blm.gov. Please reference Office of Management and Budget (OMB) Control Number 1004–0204 in the subject line of your comments. Please note that the electronic submission of comments is recommended.

FOR FURTHER INFORMATION CONTACT: To request additional information about this ICR, contact Carrie M. Richardson,

BLM National Advisory Council Coordinator, by telephone at 202–742–0657; or email at crichardson@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 the point-of-contact in the United States. You may also view the ICR at <http://www.reginfo.gov/public/do/PRAMain>.

SUPPLEMENTARY INFORMATION: In accordance with the Paperwork Reduction Act of 1995 (PRA, 44 U.S.C. 3501 *et seq.*) and 5 CFR 1320.8(d)(1), all information collections require approval under the PRA. We may not conduct, or sponsor and you are not required to respond to a collection of information unless it displays a currently valid OMB control number.

As part of our continuing effort to reduce paperwork and respondent burdens, we invite the public and other Federal agencies to comment on new, proposed, revised, and continuing collections of information. This helps us assess the impact of our information collection requirements and minimize the public's reporting burden. It also helps the public understand our information collection requirements and provide the requested data in the desired format.

We are especially interested in public comment addressing the following:

- (1) Whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- (2) The accuracy of our estimate of the burden for this collection of information, including the validity of the methodology and assumptions used;
- (3) Ways to enhance the quality, utility, and clarity of the information to be collected; and
- (4) How might the agency 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 response.

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 can 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.

Abstract: The BLM collections the information on the Resource Advisory Council Application (Form No. 1120–19) to determine education, training, and experience related to possible service on advisory committees established under the authority of Section 309 of the Federal Land Policy and Management Act (43 U.S.C. 1739) and the Federal Advisory Committee Act, 5 U.S.C. ch. 10. This information is necessary to ensure that each advisory council is structured to provide fair membership balance, both geographic and interest-specific, in terms of the functions to be performed and points of view to be represented, as prescribed by its charter. OMB's approval for the collection of information under this OMB control number is scheduled to expire on April 30, 2025. This request is for OMB to renewal for this OMB control number for an additional three (3) years.

Title of Collection: Bureau of Land Management Resource Advisory Council Application (43 CFR Subpart 1784).

OMB Control Number: 1004–0204.
Form Number: 1120–19.

Type of Review: Extension of a currently approved collection.

Respondents/Affected Public: Persons who apply for positions on Resource Advisory Councils.

Total Estimated Number of Annual Respondents: 200.

Total Estimated Number of Annual Responses: 200.

Estimated Completion Time per Response: 4 hours.

Total Estimated Number of Annual Burden Hours: 800.

Respondent's Obligation: Required to obtain or retain a benefit.

Frequency of Collection: On occasion.

Total Estimated Annual Nonhour Burden Cost: None.

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 authority for this action is the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

Darrin A. King,

Information Collection Clearance Officer.

[FR Doc. 2024-12773 Filed 6-10-24; 8:45 am]

BILLING CODE 4331-31-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0038071; PPWOCRADN0-PCU00RP14.R50000]

Notice of Intended Repatriation: School for Advanced Research, Santa Fe, NM

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the School for Advanced Research (SAR), 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 July 11, 2024.

ADDRESSES: Elysia Poon, School for Advanced Research, 660 Garcia Street, Santa Fe, NM 87505, telephone (505) 954-7205, email poon@sarsf.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 School for

Advanced Research, 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 11 cultural items have been requested for repatriation. The 11 objects of cultural patrimony are bowls, jars, container, pot rings, tablita, and offering set.

1. Pueblo of Acoma, Storage Jar, 1800-1840, clay and paints. Donated by Andrew Dasburg, Santa Fe, NM, in 1931.

2. Pueblo of Acoma, Water Jar, clay and paints. Indian Arts Fund purchase from the Spanish and Indian Trading Company, Santa Fe, NM, in 1943.

3. Pueblo of Acoma, Pot Ring, corn husk and willow. Indian Arts Fund purchase from unknown source at Acoma Pueblo, NM, in 1928.

4. Pueblo of Acoma, Pot Ring, yucca and dyes. Indian Arts Fund purchase from Maria Chino at Acoma Pueblo, January 29, 1931.

5. Pueblo of Acoma, Pot Ring, yucca and dyes. Indian Arts Fund purchase from Maria Cimarron, Acoma Pueblo, NM, in 1932.

6. Pueblo of Acoma, Bowl, wood and rawhide. Donated by Kenneth M. Chapman, Santa Fe, NM, in 1934; donor purchased it from an unknown source at Acoma Pueblo, NM, in 1928.

7. Unknown (Pueblo), Container, rawhide. Bequeathed by Mary Austin, Santa Fe, NM; received by the Indian Arts Fund in 1940.

8. Pueblo of Acoma, Tablita, wood, paint, and wax crayon. Donated by the Estate of Amelia Elizabeth White. Chemically treated, 3/24/1978, likely with ORB fog, a pyrethrins product.

9. Pueblo of Acoma, Bowl, clay and paints. Bequeathed by James Richard (Rick) Dillingham II; received at SAR in 1994.

10. Pueblo of Acoma, Bowl, clay and paints. Bequeathed by James Richard (Rick) Dillingham II; received at SAR in 1994.

11. Pueblo of Acoma, Christmas Offering Set (32 pieces), clay. Bequeathed by James Richard (Rick) Dillingham II; received at SAR in 1994.

Determinations

The School for Advanced Research has determined that:

- The 11 items 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 Pueblo of Acoma, New Mexico.

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 July 11, 2024. If competing requests for repatriation are received, the School for Advanced Research 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 School for Advanced Research 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024-12717 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-NERO-CACO-37864; PPNECACOS0, PPMPSPD1Z.YM0000]

Cape Cod National Seashore Advisory Commission Notice of Public Meetings

AGENCY: National Park Service, Interior.

ACTION: Meeting notice.

SUMMARY: In accordance with the Federal Advisory Committee Act of 1972, as amended, the National Park Service (NPS) is hereby giving notice of the 310th, 311th, 312th and 313th meetings of the Cape Cod National

Seashore Advisory Commission (Commission).

DATES: The Commission will meet on Monday, July 1, 2024; Monday, August 5, 2024; Monday, September 9, 2024; and Monday, October 7, 2024. All scheduled meetings will begin at 1 p.m. and will end by 4 p.m. (eastern time).

ADDRESSES: All meetings will be held at the Salt Pond Visitors Center, 50 Nauset Road, Eastham, Massachusetts 02642. Information on joining the teleconference will be made available to the public on the Cape Cod National Seashore website at least two weeks prior to the meetings at <https://www.nps.gov/caco/learn/management/advisory-commission.htm>.

FOR FURTHER INFORMATION CONTACT: Jennifer Flynn, Superintendent and Designated Federal Officer, Cape Cod National Seashore, 99 Marconi Site Road, Wellfleet, Massachusetts 02667, telephone (508) 771-2144 or caco_superintendent@nps.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 the point-of-contact in the United States.

SUPPLEMENTARY INFORMATION: The Commission was established by section 8 of Public Law 87-126, as amended, and expired on September 26, 2018. The Commission was reestablished by Div. DD, title VI, subtitle B, section 613 of Public Law 117-328, the Consolidated Appropriations Act, 2023. The Commission's new termination date is September 26, 2029. The purpose of the Commission is to consult with the Secretary of the Interior, or her designee, with respect to matters relating to the development of Cape Cod National Seashore, and with respect to carrying out the provisions of the Act establishing the Seashore. The meetings are open to the public. Interested persons may make oral presentations to the Commission. Such requests should be made to the Superintendent at the beginning of the meeting. Depending on the number of persons wishing to speak, and the time available, the time for individual comments may be limited. Written comments can be sent to Jennifer Flynn (see **FOR FURTHER INFORMATION CONTACT**). All comments received will be provided to the Commission.

The Commission meeting location may change based on inclement weather or exceptional circumstances. If a

meeting location is changed, the Superintendent will issue a press release and use local newspapers to announce the change. Detailed minutes of the meeting will be available for public inspection within 90 days of the meeting.

Purpose of the Meeting: The standing agenda/purpose of each meeting is to discuss the following:

1. Adoption of agenda
2. Approval of meeting minutes
3. Superintendent's report
4. Members comments
5. Meeting primary topic
6. Public comment
7. Adjournment

Focus of each meeting as follows:

July—Fresh Water
August—Zoning
September—Fire
October—Climate/Coastal Resiliency

Meeting Accessibility/Special Accommodations: The meetings are open to the public. Please make requests in advance for sign language interpreter services, assistive listening devices, language translation services, or other reasonable accommodations. We ask that you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this notice at least seven (7) business days prior to the meeting to give the Department of the Interior sufficient time to process your request. All reasonable accommodation requests are managed on a case-by-case basis.

Public Disclosure of Comments: 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 can 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.

Authority: 5 U.S.C. ch. 10.

Alma Rippes,
Chief, Office of Policy.

[FR Doc. 2024-12732 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0038068;
PPWOCRADNO-PCU00RP14.R50000]

Notice of Inventory Completion: Los Rios Community College District, Sacramento, CA

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Los Rios Community College District (LRCCD) has completed an inventory of associated funerary objects and has determined that there is a cultural affiliation between the associated funerary objects and Indian Tribes or Native Hawaiian organizations in this notice.

DATES: Repatriation of the associated funerary objects in this notice may occur on or after July 11, 2024.

ADDRESSES: Jamey Nye, Los Rios Community College District, 1919 Spanos Ct., Arden-Arcade, CA 95825, telephone (916) 568-3031, email nagpra@losrios.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 LRCCD 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, associated funerary objects removed from the Bennett Mound or Bennett site (CA-SAC-16), Sacramento County, CA have been identified. The associated funerary objects were removed sometime in or around 1932 by Jeremiah B. Lillard. Between 1923 and 1940, Lillard was president of Sacramento Junior College, now named Sacramento City College, which is one of four campuses within LRCCD. As early as July 1981, the objects were located on the American River College campus, another campus within LRCCD. The five associated funerary objects are two stone charmstones, one stone projectile point, one bone awl, and one abalone ornament. LRCCD has no knowledge of any potentially hazardous substances being used to treat the associated funerary objects.

Cultural Affiliation

Based on the information available and the results of consultation, cultural affiliation is clearly identified by the information available about the associated funerary objects described in this notice.

Determinations

LRCCD has determined that:

- The five 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 associated funerary objects described in this notice and the Buena Vista Rancheria of Me-Wuk Indians of California; California Valley Miwok Tribe, California; Chicken Ranch Rancheria of Me-Wuk Indians of California; Ione Band of Miwok Indians of California; Jackson Band of Miwok Indians; Shingle Springs Band of Miwok Indians, Shingle Springs Rancheria (Verona Tract), California; Tuolumne Band of Me-Wuk Indians of the Tuolumne Rancheria of California; United Auburn Indian Community of the Auburn Rancheria of California; and the Wilton Rancheria, California

Requests for Repatriation

Written requests for repatriation of the 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 associated funerary objects in this notice to a requestor may occur on or after July 11, 2024. If competing requests for repatriation are received, LRCCD must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the associated funerary objects are considered a single request and not competing requests. LRCCD 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024-12714 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0038052; PPWOCRADNO-PCU00RP14.R50000]

Notice of Intended Repatriation: University of Michigan, Ann Arbor, MI

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the University of Michigan intends to repatriate certain cultural items that meet the definition of unassociated funerary objects and that have a known lineal descendant.

DATES: Repatriation of the cultural items in this notice may occur on or after July 11, 2024.

ADDRESSES: Dr. Ben Secunda, NAGPRA Office Managing Director, University of Michigan, Office of Research, Suite G269, Lane Hall, Ann Arbor, MI 48109-1274, telephone (734) 615-8936, email bsecunda@umich.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 University of Michigan 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 two cultural items have been requested for repatriation. The two unassociated funerary objects are one lot of nickel silver brooches and one lot of shell and glass beads. On an unknown date in 1913, two lots of Cultural Items were removed from the Ft. Wayne site in Allen Co, Indiana on the property of Dr. Gillis, Lawton Place, and donated to the University of Michigan Museum of Anthropological Archaeology (UMMAA) by Mrs. Gertrude E. Dean on June 19, 1936. UMMAA records note "a sword with the burial. Someone in Wash. D. C. got most of the material . . . silver crosses and arm bands." The site is dated to the post-contact A.D. 1700-1850 based on diagnostic artifacts. This location is known to be the burial site of the Miami leader, Little Turtle. The University of Michigan has no record of, nor do its officials have any knowledge of, any treatment of items with pesticides, preservatives, or other

substances that represent a potential hazard to the collection(s) or to persons handling the collection(s).

Determinations

The University of Michigan has determined that:

- The two 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.

- The known lineal descendants, Daryl Baldwin (Miami Tribe of Oklahoma) and Scott Willard (Miami Tribe of Oklahoma), are connected to the cultural items described in this notice.

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 July 11, 2024. If competing requests for repatriation are received, the University of Michigan 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 University of Michigan 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–12708 Filed 6–10–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0038055;
PPWOCRADN0–PCU00RP14.R50000]

Notice of Inventory Completion: Department of the Interior, Bureau of Land Management, Canyons of the Ancients Visitors Center and Museum, Dolores, CO

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the U.S. Department of the Interior, Bureau of Land Management, Canyons of the Ancients Visitors Center and Museum 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. The human remains and associated funerary object were removed from San Miguel County, Colorado.

DATES: Repatriation of the human remains and associated funerary objects in this notice may occur on or after July 11, 2024.

ADDRESSES: Ray O'Neil, Monument Manager, Bureau of Land Management, Canyons of the Ancients National Monument, 27501 Highway 184, Dolores, CO 81323, telephone (303) 882–5600, email roneil@blm.gov.

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 Canyons of the Ancients Visitors Center and Museum, Bureau of Land Management, Dolores, CO, and additional information on the determinations in this notice, including the results of consultation, can be found in its inventory or related records. The National Park Service is not responsible for the determinations in this notice.

Abstract of Information Available

Human remains representing, at least, one individual have been identified. The one associated funerary object is a bone awl. The human remains were

removed from the burial site in San Miguel County, CO, in 1983 after the site (5SM790) had been vandalized sometime during the winter of 1982–1983. The burial appeared to be a cairn burial, comprised of about 20 sandstone cobbles and two groundstone slabs, within a rockshelter. A detailed assessment of the human remains was made by archaeologists in 1983 and in 1994, who determined the individual was of Native American descent. The human remains belong to an adult female. With the exception of the right arm and hand, one lumbar vertebra, and rib fragments, the upper portion of the body was completely missing. Based upon the burial context, as well as a radiocarbon date from charcoal included in the burial pit (A.D. 460 ± 140), the site is reasonably believed to be from, in archaeological terms, the late Archaic or Formative period.

Cultural Affiliation

Based on the information available and the results of consultation, cultural affiliation is reasonably identified by the geographical location of the human remains and associated funerary object described in this notice.

Determinations

The BLM Canyons of the Ancients Visitors Center and Museum has determined that:

- The human remains described in this notice represent the physical remains of one individual of Native American ancestry.
- The one object described in this notice is 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 connection between the human remains and associated funerary objects described in this notice and the Hopi Tribe of Arizona; Ohkay Owingeh, New Mexico; Pueblo of Acoma, New Mexico; Pueblo of Cochiti, New Mexico; Pueblo of Isleta, New Mexico; Pueblo of Jemez, New Mexico; Pueblo of Laguna, New Mexico; Pueblo of Nambe, New Mexico; Pueblo of Picuris, New Mexico; Pueblo of Pojoaque, New Mexico; Pueblo of San Felipe, New Mexico; Pueblo of San Ildefonso, New Mexico; Pueblo of Sandia, New Mexico; Pueblo of Santa Ana, New Mexico; Pueblo of Santa Clara, New Mexico; Pueblo of Taos, New Mexico; Pueblo of Tesuque, New Mexico; Pueblo of Zia, New Mexico; Santo Domingo Pueblo; Southern Ute Indian Tribe of the Southern Ute Reservation, Colorado; Ute Indian Tribe of the Uintah & Ouray Reservation, Utah; Ute Mountain Ute

Tribe; Ysleta del Sur Pueblo; and the Zuni Tribe of the Zuni Reservation, New Mexico.

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 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 an Indian Tribe or Native Hawaiian organization with cultural affiliation.

Repatriation of the human remains and associated funerary objects in this notice to a requestor may occur on or after July 11, 2024. If competing requests for repatriation are received, the BLM Canyons of the Ancients Visitors Center and Museum 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 BLM Canyons of the Ancients Visitors Center and Museum is responsible for sending a copy of this notice to the Indian Tribes 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–12711 Filed 6–10–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0038067;
PPWOCRADN0–PCU00RP14.R50000]

Notice of Inventory Completion: Western Washington University, Department of Anthropology, Bellingham, WA

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), Western Washington University (WWU), 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 removed from 45–WH–11 in Whatcom County, WA.

DATES: Repatriation of the human remains in this notice may occur on or after July 11, 2024.

ADDRESSES: Dr. Judith Pine, Western Washington University, Department of Anthropology, Arntzen Hall 340, 516 High Street, Bellingham, WA 98225, telephone (360) 650–4783, email pinej@wwu.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 WWU, and additional information on the determinations in this notice, including the results of consultation, can be found in its 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 least, one individual have been reasonably identified. No associated funerary objects are present.

The human remains in this notice were removed from 45–WH–11 (Birch Bay, Washington) by students from Western Washington University under the direction of WWU professor Dr. Garland Grabert in the fall of 1970. Notes indicated that surface collection and a small-scale excavation occurred; the human remains were found in Test Cut #2 but were not recognized as human remains until after 2018. No known individuals were identified. No hazardous chemicals are known to have been used to treat the human remains while in the custody of WWU.

The human remains in this notice are connected to one or more identifiable earlier groups, tribes, peoples, or cultures. There is a relationship of shared group identity between the identifiable earlier groups, tribes, peoples, or cultures and one or more Indian Tribes or Native Hawaiian organizations. The following types of information were used to reasonably trace the relationship: anthropological information, archaeological information, geographical information, historical information, and oral tradition.

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 WWU has determined that:

- The human remains described in this notice represent the physical remains of one individual of Native American ancestry.
- There is a connection between the human remains described in this notice and the Lummi Tribe of the Lummi Reservation and the Nooksack Indian Tribe.

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. 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 an Indian Tribe or Native Hawaiian organization with cultural affiliation.

Repatriation of the human remains described in this notice to a requestor may occur on or after July 11, 2024. If competing requests for repatriation are received, the WWU 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 WWU 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024–12713 Filed 6–10–24; 8:45 am]

BILLING CODE 4312–52–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–WASO–NAGPRA–NPS0038054; PPWOCRADN0–PCU00RP14.R50000]

Notice of Intended Disposition: General Services Administration, Fort Worth, TX

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the General Services Administration (GSA) 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 July 11, 2024. If no claim for disposition is received by June 11, 2025, the human remains or cultural items in this notice will become unclaimed human remains or cultural items.

ADDRESSES: Victoria Clow, General Services Administration, 819 Taylor Street, 11th Floor, Fort Worth, TX 76012, telephone (817) 978–0199, email Victoria.clow@gsa.gov.

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 General Services Administration, 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

The one object of cultural patrimony is a small, complete stone ax. The object was found on Federal property within the city of Santa Fe, Santa Fe County, New Mexico. In November of 2019, during sprinkler maintenance work outside of the archaeological monitoring area, an irrigation worker discovered an artifact in disturbed soils identified as construction fill. The irrigation worker submitted the discovery to the New Mexico Office of Archeological Studies with the Department of Cultural Affairs. An archaeologist with that office notified the General Services Administration and identified the object as likely having ongoing historical, traditional, or cultural importance.

Determinations

The General Services Administration has determined that:

- The one object 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.

- The Pueblo of Tesuque, New Mexico has priority for disposition of the cultural item described in this notice.

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 June 11, 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 July 11, 2024. If competing claims for disposition are received, the General Services Administration 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 General Services Administration 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024-12710 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS-WASO-NAGPRA-NPS0038056;
PPWOCRADNO-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 Rosebud Indian Reservation, SD, and Flandreau Indian School, Moody County, SD.

DATES: Repatriation of the human remains in this notice may occur on or after July 11, 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, two individuals were collected at the Rosebud Indian Reservation, SD. The human remains are hair clippings collected from one individual who was recorded as being 58 years old and one individual who was recorded as being 46 years old and identified as "Yankton." William O. Roberts took the hair clippings at the Rosebud Indian Reservation between 1930 and 1933. Roberts sent the hair clippings to George Woodbury, who donated the hair clippings to the PMAE in 1935. No associated funerary objects are present.

Based on the information available, human remains representing, at minimum, one individual was collected at the Flandreau Indian School, Moody County, SD. The human remains are hair clippings collected from one individual who was recorded as being 22 years old and identified as "Sioux." George E. Peters took the hair clippings at the Flandreau Indian School between 1930 and 1933. Peters 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 available information 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 three individuals of Native American ancestry.
- There is a reasonable connection between the human remains described in this notice and the Yankton Sioux Tribe of South Dakota.

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 July 11, 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024-12712 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR**National Park Service**

[NPS-WASO-NAGPRA-NPS0038070;
PPWOCRADNO-PCU00RP14.R50000]

**Notice of Intended Disposition:
Department of the Interior, Bureau of
Reclamation, Upper Colorado Basin
Region, Provo, UT**

AGENCY: National Park Service, Interior.
ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), U.S. Department of the Interior, Bureau of Reclamation (Reclamation), Upper Colorado Basin Region intends to carry out the disposition of human remains 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 July 11, 2024. If no claim for disposition is received by June 11, 2025, the human remains in this notice will become unclaimed human remains.

ADDRESSES: Dr. Zachary Nelson, Bureau of Reclamation, Upper Colorado Basin Region, 302 East Lakeview Parkway, Provo, UT 84606, telephone (801) 379-1164, email znelson@usbr.gov.

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 Reclamation, Upper Colorado Basin Region, and additional information on the human remains 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, human remains representing, at least, one individual has been reasonably identified. No associated funerary objects are present. On May 9, 2021, at Red Fleet Reservoir in Uintah County, Utah, human remains were discovered along the shore at the water line. No identified burial was located.

Determinations

The Reclamation Upper Colorado Basin Region has determined that:

- The human remains described in this notice represent the physical remains of one individual of Native American ancestry.

- The Ute Indian Tribe of the Uintah & Ouray Reservation, Utah has priority for disposition of the human remains described in this notice.

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 June 11, 2025, the human remains in this notice will become unclaimed human remains. 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 July 11, 2024. If competing claims for disposition are received, Reclamation Upper Colorado Basin Region 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 Reclamation Upper Colorado Basin Region 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024-12716 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR**National Park Service**

[NPS-WASO-NAGPRA-NPS0038072;
PPWOCRADNO-PCU00RP14.R50000]

**Notice of Intended Repatriation:
Department of the Interior, National
Park Service, Pipe Spring National
Monument, Fredonia, AZ**

AGENCY: National Park Service, Interior.
ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the U.S. Department of the Interior, National

Park Service, Pipe Spring National Monument (PISP) 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 July 11, 2024.

ADDRESSES: Amanda McCutcheon, Superintendent, Pipe Spring National Monument, 406 N Pipe Spring Road, Fredonia, AZ 86022, telephone (928) 643-7105, email amanda_mccutcheon@nps.gov.

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 Superintendent, PISP, and additional information on the determinations in this notice, including the results of consultation, can be found in the summary or related records.

Abstract of Information Available

A total of eight cultural items have been requested for repatriation. The eight unassociated funerary objects are two mineral pigments, two lots of shell beads/fragments, one ceramic pot, one ceramic bowl, and two pipe bowls. Journal entries from PISP's first superintendent, Leonard Heaton, describes his finding of these objects alongside human remains. These entries span several years, from 1928 to 1940, and do not provide specifics as to exact locations. The artifacts were not cataloged at the time of discovery and were later found in collections in 1985, along with hand-written envelopes from Heaton.

Determinations

PISP has determined that:

- The eight unassociated funerary objects described above are reasonably believed to have been placed intentionally with or near individual human remains, and are connected, either at the time of death or later as part of the death rite or ceremony and are believed, by a preponderance of the evidence, to have been removed from a specific burial site 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 Kaibab Band of Paiute Indians of the Kaibab Indian Reservation, Arizona.

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 July 11, 2024. If competing requests for repatriation are received, PISP 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. PISP 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024-12718 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR**National Park Service**

[NPS-WASO-NAGPRA-NPS0038053;
PPWOCRADN0-PCU00RP14.R50000]

Notice of Inventory Completion: Grand Rapids Public Museum, Grand Rapids, MI

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Grand Rapids Public Museum 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 July 11, 2024.

ADDRESSES: Alex Forist, 272 Pearl Street NW, Grand Rapids, MI 49504, telephone (616) 929-1809, email aforist@grpm.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 Grand Rapids Public Museum, 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 least, one individual has been reasonably identified. The three associated funerary objects are an ax head, steel, and flint. At an unknown date, the related ancestral remains and associated funerary objects were found wrapped in birch bark on Sugar Island about 18 miles from Sault Ste. Marie, Chippewa County, MI by Charles Bradshaw during a house excavation. At an unknown date, they were acquired by Isaac Lemon. In 1907, they were donated to the Kent Scientific Museum (now the Grand Rapids Public Museum).

Cultural Affiliation

Based on the information available and the results of consultation, cultural affiliation is reasonably identified by the geographical location or acquisition history of the human remains and associated funerary objects described in this notice.

Determinations

The Grand Rapids Public Museum has determined that:

- The human remains described in this notice represent the physical remains of one individual of Native American ancestry.
- The three 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 Bay Mills Indian Community, Michigan and the Sault Ste. Marie Tribe of Chippewa Indians, Michigan.

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 July 11, 2024. If competing requests for repatriation are received, the Grand Rapids Public Museum 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 Grand Rapids Public Museum 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024-12709 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

DEPARTMENT OF THE INTERIOR**National Park Service**

[NPS-WASO-NAGPRA-NPS0038069;
PPWOCRADN0-PCU00RP14.R50000]

Notice of Inventory Completion: Mukwonago Community Library, Mukwonago, WI

AGENCY: National Park Service, Interior.

ACTION: Notice.

SUMMARY: In accordance with the Native American Graves Protection and Repatriation Act (NAGPRA), the Mukwonago Community Library has completed an inventory of associated funerary objects and has determined that there is a cultural affiliation between the associated funerary objects and Indian Tribes or Native Hawaiian organizations in this notice.

DATES: Repatriation of the associated funerary objects in this notice may occur on or after July 11, 2024.

ADDRESSES: Abby Armour, Mukwonago Community Library, 511 Division Street,

Mukwonago, WI 53149, telephone (262) 363-6411, email nagpra@mukwonagolibrary.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 Mukwonago Community Library, 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, associated funerary objects removed from Bennett Mound or Bennett Site (CA-SAC-16), Sacramento County, CA have been identified. On an unknown date, the associated funerary objects were likely removed by Jeremiah B. Lillard, based on handwriting found on item tags. On a date prior to 1965, Arthur Grutzmacher, a collector and dealer from Mukwonago, WI, obtained the associated funerary objects. Following his death in 1965, the associated funerary objects were bequeathed to the Mukwonago Community Library. The three associated funerary objects are one lot of shell beads, one lot of glass and stone beads, and one bone tube. Mukwonago Community Library has no knowledge of any potentially hazardous substances used to treat the associated funerary objects.

Cultural Affiliation

Based on the information available and the results of consultation, cultural affiliation is clearly identified by the information available about the associated funerary objects described in this notice.

Determinations

The Mukwonago Community Library has determined that:

- The three 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 associated funerary objects described in this notice and the Buena Vista Rancheria of Me-Wuk Indians of California; California Valley Miwok Tribe, California; Chicken Ranch Rancheria of Me-Wuk Indians of California; Ione Band of Miwok Indians of California; Jackson Band of Miwok Indians; Shingle Springs Band of Miwok

Indians, Shingle Springs Rancheria (Verona Tract), California; Tuolumne Band of Me-Wuk Indians of the Tuolumne Rancheria of California; United Auburn Indian Community of the Auburn Rancheria of California; and the Wilton Rancheria, California.

Requests for Repatriation

Written requests for repatriation of the 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 associated funerary objects in this notice to a requestor may occur on or after July 11, 2024. If competing requests for repatriation are received, the Mukwonago Community Library must determine the most appropriate requestor prior to repatriation. Requests for joint repatriation of the associated funerary objects are considered a single request and not competing requests. The Mukwonago Community Library 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: May 31, 2024.

Melanie O'Brien,

Manager, National NAGPRA Program.

[FR Doc. 2024-12715 Filed 6-10-24; 8:45 am]

BILLING CODE 4312-52-P

INTERNATIONAL TRADE COMMISSION

[Investigation Nos. 701-TA-728 and 731-TA-1697 (Preliminary)]

Vanillin From China; Institution of Antidumping and Countervailing Duty Investigations and Scheduling of Preliminary Phase Investigations

AGENCY: United States International Trade Commission.

ACTION: Notice.

SUMMARY: The Commission hereby gives notice of the institution of investigations

and commencement of preliminary phase antidumping and countervailing duty investigations Nos. 701-TA-728 and 731-TA-1697 (Preliminary) pursuant to the Tariff Act of 1930 ("the Act") to determine whether there is a reasonable indication that an industry in the United States is materially injured or threatened with material injury, or the establishment of an industry in the United States is materially retarded, by reason of imports of vanillin from China, provided for in subheadings 2912.41.00 and 2912.42.00 of the Harmonized Tariff Schedule of the United States, that are alleged to be sold in the United States at less than fair value and alleged to be subsidized by the Government of China. Unless the Department of Commerce ("Commerce") extends the time for initiation, the Commission must reach a preliminary determination in antidumping and countervailing duty investigations in 45 days, or in this case by July 22, 2024. The Commission's views must be transmitted to Commerce within five business days thereafter, or by July 29, 2024.

DATES: June 5, 2024.

FOR FURTHER INFORMATION CONTACT:

Caitlyn Hendricks-Costello (202-205-2058), Office of Investigations, U.S. International Trade Commission, 500 E Street SW, Washington, DC 20436. Hearing-impaired persons can obtain information on this matter by contacting the Commission's TDD terminal on 202-205-1810. Persons with mobility impairments who will need special assistance in gaining access to the Commission should contact the Office of the Secretary at 202-205-2000. General information concerning the Commission may also be obtained by accessing its internet server (<https://www.usitc.gov>). The public record for these investigations may be viewed on the Commission's electronic docket (EDIS) at <https://edis.usitc.gov>.

SUPPLEMENTARY INFORMATION:

Background.—These investigations are being instituted, pursuant to sections 703(a) and 733(a) of the Tariff Act of 1930 (19 U.S.C. 1671b(a) and 1673b(a)), in response to a petition filed on June 5, 2024, by Solvay USA LLC, Baton Rouge, Louisiana.

For further information concerning the conduct of these investigations and rules of general application, consult the Commission's Rules of Practice and Procedure, part 201, subparts A and B (19 CFR part 201), and part 207, subparts A and B (19 CFR part 207).

Participation in the investigations and public service list.—Persons (other than petitioners) wishing to participate in the

investigations as parties must file an entry of appearance with the Secretary to the Commission, as provided in §§ 201.11 and 207.10 of the Commission's rules, not later than seven days after publication of this notice in the **Federal Register**. Industrial users and (if the merchandise under investigation is sold at the retail level) representative consumer organizations have the right to appear as parties in Commission antidumping duty and countervailing duty investigations. The Secretary will prepare a public service list containing the names and addresses of all persons, or their representatives, who are parties to these investigations upon the expiration of the period for filing entries of appearance.

Limited disclosure of business proprietary information (BPI) under an administrative protective order (APO) and BPI service list.—Pursuant to § 207.7(a) of the Commission's rules, the Secretary will make BPI gathered in these investigations available to authorized applicants representing interested parties (as defined in 19 U.S.C. 1677(9)) who are parties to the investigations under the APO issued in the investigations, provided that the application is made not later than seven days after the publication of this notice in the **Federal Register**. A separate service list will be maintained by the Secretary for those parties authorized to receive BPI under the APO.

Conference.—The Office of Investigations will hold a staff conference in connection with the preliminary phase of these investigations beginning at 9:30 a.m. on Wednesday, June 26, 2024. Requests to appear at the conference should be emailed to preliminaryconferences@usitc.gov (DO NOT FILE ON EDIS) on or before Monday, June 24, 2024. Please provide an email address for each conference participant in the email. Information on conference procedures, format, and participation, including guidance for requests to appear as a witness via videoconference, will be available on the Commission's Public Calendar (Calendar (USITC) | United States International Trade Commission). A nonparty who has testimony that may aid the Commission's deliberations may request permission to participate by submitting a short statement.

Please note the Secretary's Office will accept only electronic filings during this time. Filings must be made through the Commission's Electronic Document Information System (EDIS, <https://edis.usitc.gov>). No in-person paper-based filings or paper copies of any electronic filings will be accepted until further notice.

Written submissions.—As provided in §§ 201.8 and 207.15 of the Commission's rules, any person may submit to the Commission on or before 5:15 p.m. on July 1, 2024, a written brief containing information and arguments pertinent to the subject matter of the investigations. Parties shall file written testimony and supplementary material in connection with their presentation at the conference no later than noon on June 25, 2024. All written submissions must conform with the provisions of § 201.8 of the Commission's rules; any submissions that contain BPI must also conform with the requirements of §§ 201.6, 207.3, and 207.7 of the Commission's rules. The Commission's *Handbook on Filing Procedures*, available on the Commission's website at https://www.usitc.gov/documents/handbook_on_filing_procedures.pdf, elaborates upon the Commission's procedures with respect to filings.

In accordance with §§ 201.16(c) and 207.3 of the rules, each document filed by a party to the investigations must be served on all other parties to the investigations (as identified by either the public or BPI service list), and a certificate of service must be timely filed. The Secretary will not accept a document for filing without a certificate of service.

Certification.—Pursuant to § 207.3 of the Commission's rules, any person submitting information to the Commission in connection with these investigations must certify that the information is accurate and complete to the best of the submitter's knowledge. In making the certification, the submitter will acknowledge that any information that it submits to the Commission during these investigations may be disclosed to and used: (i) by the Commission, its employees and Offices, and contract personnel (a) for developing or maintaining the records of these or related investigations or reviews, or (b) in internal investigations, audits, reviews, and evaluations relating to the programs, personnel, and operations of the Commission including under 5 U.S.C. Appendix 3; or (ii) by U.S. government employees and contract personnel, solely for cybersecurity purposes. All contract personnel will sign appropriate nondisclosure agreements.

Authority: These investigations are being conducted under authority of title VII of the Tariff Act of 1930; this notice is published pursuant to § 207.12 of the Commission's rules.

By order of the Commission.

Issued: June 5, 2024.

Lisa Barton,

Secretary to the Commission.

[FR Doc. 2024–12695 Filed 6–10–24; 8:45 am]

BILLING CODE 7020–02–P

INTERNATIONAL TRADE COMMISSION

[Investigation Nos. 701–TA–688 and 731–TA–1612–1613 and 1615–1617 (Final)]

Brass Rod From Brazil, India, Mexico, South Africa, and South Korea; Determinations

On the basis of the record¹ developed in the subject investigations, the United States International Trade Commission ("Commission") determines, pursuant to the Tariff Act of 1930 ("the Act"), that an industry in the United States is materially injured by reason of imports of brass rod from Brazil, India, Mexico, South Africa, and South Korea, provided for in subheadings 7407.21.15, 7407.21.30, 7407.21.70, and 7407.21.90 of the Harmonized Tariff Schedule of the United States, that have been found by the U.S. Department of Commerce ("Commerce") to be sold in the United States at less than fair value ("LTFV"), and imports of the subject merchandise from South Korea that have been found by Commerce to be subsidized by the government of South Korea.^{2,3}

Background

The Commission instituted these investigations effective April 27, 2023, following receipt of petitions filed with the Commission and Commerce by American Brass Rod Fair Trade Coalition, Washington, District of Columbia; Mueller Brass Co., Port Huron, Michigan; and Wieland Chase LLC, Montpelier, Ohio. The Commission scheduled the final phase of the investigations following notification of a preliminary determination by Commerce that imports of brass rod from India were subsidized within the meaning of section 703(b) of the Act (19 U.S.C. 1671b(b)). Notice of the scheduling of the final phase of the Commission's investigations and of a public hearing to be held in connection therewith was given by posting copies of the notice in the Office of the Secretary, U.S. International Trade Commission, Washington, DC, and by publishing the

¹ The record is defined in § 207.2(f) of the Commission's Rules of Practice and Procedure (19 CFR 207.2(f)).

² 89 FR 29290, 89 FR 29303, 89 FR 29300, 89 FR 29305, 89 FR 29292, 89 FR 29298, and 89 FR 29290, April 22, 2024.

³ Commissioner David S. Johanson dissenting.

notice in the **Federal Register** of October 5, 2023 (88 FR 6922). The Commission conducted its hearing on December 12, 2023. All persons who requested the opportunity were permitted to participate.

The investigation schedules became staggered when Commerce did not align its countervailing duty investigation with its antidumping duty investigation regarding India, and reached an earlier final countervailing duty determination. On February 1, 2024, the Commission issued a final affirmative determination in its countervailing duty investigation of brass rod from India (89 FR 8440, February 7, 2024). Following notification of final determinations by Commerce that imports of brass rod from Brazil, India, Mexico, South Africa, and South Korea were being sold at LTFV within the meaning of section 735(a) of the Act (19 U.S.C. 1673d(a)) and imports of brass rod from South Korea were being subsidized by the government of South Korea within the meaning of section 705(a) of the Act (19 U.S.C. 1671d(a)), notice of the supplemental scheduling of the final phase of the Commission's antidumping duty investigations regarding brass rod from Brazil, India, Mexico, South Africa, and South Korea and countervailing duty investigation regarding brass rod from South Korea was given by posting copies of the notice in the Office of the Secretary, U.S. International Trade Commission, Washington, DC, and by publishing the notice in the **Federal Register** of May 1, 2024 (89 FR 35236).

The Commission made these determinations pursuant to § 705(b) and § 735(b) of the Act (19 U.S.C. 1671d(b) and 19 U.S.C. 1673d(b)). It completed and filed its determinations in these investigations on June 5, 2024. The views of the Commission are contained in USITC Publication 5513 (June 2024), entitled *Brass Rod from Brazil, India, Mexico, South Africa, and South Korea: Investigation Nos. 701–TA–688 and 731–TA–1612–1613 and 1615–1617 (Final)*.

By order of the Commission.

Issued: June 5, 2024.

Lisa Barton,

Secretary to the Commission.

[FR Doc. 2024–12696 Filed 6–10–24; 8:45 am]

BILLING CODE 7020–02–P

DEPARTMENT OF JUSTICE

Antitrust Division

State of Ohio et al. v. National Collegiate Athletics Association; Proposed Final Judgment and Competitive Impact Statement

Notice is hereby given pursuant to the Antitrust Procedures and Penalties Act, 15 U.S.C. 16(b)–(h), that a proposed Final Judgment, Stipulation, and Competitive Impact Statement have been filed with the United States District Court for the Northern District of West Virginia in *State of Ohio et al. v. National Collegiate Athletics Association*, Civil Action No. 1:23–cv–100. On January 18, 2024, the United States, along with ten states and the District of Columbia, filed an Amended Complaint alleging that the NCAA's Division I rule requiring student athletes who transfer between institutions to complete a year in residence before being eligible to compete in intercollegiate contests unreasonably restrained trade in violation of section 1 of the Sherman Act, 15 U.S.C. 1. The proposed Final Judgment, filed on May 30, 2024, requires the NCAA to refrain from enforcing the offending rules and to restore eligibility to certain affected student athletes.

Copies of the Amended Complaint, proposed Final Judgment, and Competitive Impact Statement are available for inspection on the Antitrust Division's website at <http://www.justice.gov/atr> and at the Office of the Clerk of the United States District Court for the Northern District of West Virginia. Copies of these materials may be obtained from the Antitrust Division upon request and payment of the copying fee set by Department of Justice regulations.

Public comment is invited within 60 days of the date of this notice. Such comments, including the name of the submitter, and responses thereto, will be posted on the Antitrust Division's website, filed with the Court, and, under certain circumstances, published in the **Federal Register**. Comments should be submitted in English and directed to Yvette Tarlov, Chief, Media, Entertainment & Communications, Antitrust Division, Department of Justice, 450 Fifth Street NW, Suite 7000,

Washington, DC 20530 (email address: Yvette.Tarlov@usdoj.gov).

Suzanne Morris,

Deputy Director, Civil Enforcement Operations, Antitrust Division.

In the United States District Court for the Northern District of West Virginia Clarksburg Division

Amended Complaint for Injunctive Relief

State of Ohio, 30 E. Broad St., 26th Floor, Columbus, OH 43215, Commonwealth of Virginia, 202 North 9th Street, Richmond, VA 23219, District of Columbia, 400 6th Street NW, 10th Floor, Washington, DC 20001, State of Colorado, 1300 Broadway, 7th Floor, Denver, CO 80203, State of Illinois, 100 West Randolph Street, Chicago, IL 60601, State of Minnesota, 445 Minnesota St., Suite #1400, St. Paul, MN 55101, State of Mississippi, 550 High St., P.O. Box 220, Jackson, MS 39205, State of New York, 28 Liberty Street, New York, NY 10005, State of North Carolina, 114 W. Edenton Street, Raleigh, NC 27603, State of Tennessee, P.O. Box 20207, Nashville, TN 37202, State of West Virginia, P.O. Box 1789, Charleston, WV 25326, and United States of America, U.S. Department of Justice, 950 Pennsylvania Avenue NW, Washington, DC 20530, Plaintiffs, v. National Collegiate Athletic Association, 700 W Washington Street, P.O. Box 6222, Indianapolis, IN 46206–6222, Defendant.

Bailey,
Case No: 1:23–cv–00100
Judge Bailey

Amended Complaint for Injunctive Relief

1. The State of Ohio, Commonwealth of Virginia, District of Columbia, and States of Colorado, Illinois, Minnesota, Mississippi, New York, North Carolina, Tennessee, and West Virginia (“Plaintiff States”) and the United States of America bring this action to challenge Bylaw 14.5.5.1 (“Transfer Eligibility Rule”) of Defendant, the National Collegiate Athletic Association (“NCAA”). This bylaw imposes a one-year delay in the eligibility of certain college athletes transferring between NCAA member institutions and unjustifiably restrains the ability of these college athletes to engage in the market for their labor as NCAA Division I college athletes. This action seeks declaratory and injunctive relief against Defendant for a violation of section 1 of the Sherman Act, 15 U.S.C. 1.

Introduction

2. NCAA member institutions and their college athletes engage in intense competition on and off the field. The contests that take place on fields and courts across the nation are the most visible. But off the field, schools compete to recruit and retain talented

college athletes, and college athletes compete to market their labor to the schools of their choice.

3. In the time since the NCAA's founding in 1906, the scope and subject matter of its rules governing intercollegiate sports have expanded significantly. It has not only adopted rules to ensure the actual contests on the field are fair and safe, but it has also created rules that control off-the-field competition among its members and college athletes. Although some of these rules may be necessary to administer college sports, rules that unreasonably restrict competition between competitors, with no overriding procompetitive benefit, run headlong into this nation's antitrust laws which are premised on the belief that market forces provide the best outcomes.

4. One such NCAA rule is the Transfer Eligibility Rule, which restricts the eligibility of college athletes who transfer between Division I schools. The NCAA claims that this Rule promotes academic well-being of college athletes and preserves its amateurism model. But the connection between the Rule and academic well-being or athletic amateurism is tenuous at best and is outweighed by the harm it does to college athletes and consumers of college athletics. In the language of antitrust law, the Transfer Eligibility Rule is a no-poach agreement between horizontal competitor member schools that serves to allocate the market for the labor of NCAA Division I college athletes. This agreement plainly violates the Sherman Act. The fact that it was created under the auspices of the NCAA does not shield it from antitrust scrutiny. In contrast to college athletes, students with academic or music scholarships can freely transfer institutions without facing similar restraints on their ability to practice their craft. Likewise, coaches and administrators face no comparable barriers.

5. The Transfer Eligibility Rule requires a year of academic residency before a transferring Division I college athlete is eligible to participate in NCAA athletic competition. Underscoring its anticompetitive nature, the rule is not universally applied. A college athlete's first transfer is excepted from this process, and there is a discretionary waiver process. But the Rule remains the default for Division I college athletes who transfer a second time.

6. For NCAA college athletes, a one-year waiting period for eligibility can be devastating. This amounts to 20% of the total time allotted by NCAA regulations for the completion of the college

athlete's total seasons of eligibility. Furthermore, only by competing on the field or court can the college athlete receive the full benefits of participation in Division I NCAA athletics.

7. The Transfer Eligibility Rule artificially deters players and teams from achieving optimal matches by forcing college athletes to weigh the one-year ineligibility period against the benefits of moving to a better matched school. It is ironic that this rule, stylized as promoting the welfare of college athletes, strips them of the agency and opportunity to optimize their own welfare as they see fit.

8. Though the NCAA is an association of member institutions that compete against each other to attract revenues, fans, and college athletes, it has enacted and enforced anticompetitive rules and policies that act as an unlawful barrier on the ability of certain college athletes and universities to compete against each other.

9. Plaintiff States and the United States bring this action to put a stop to Defendant's unjustified overreach into the lives and careers of college athletes, to prevent the unjustified anticompetitive restriction on universities who seek to compete for college athletes, and to restore freedom of economic opportunity.

Jurisdiction and Venue

10. This Court has jurisdiction over this action under section 1 of the Sherman Act, 15 U.S.C. 1, section 26 of the Clayton Act, 15 U.S.C. 26, and under 28 U.S.C. 1331 and 1337.

11. This Court may exercise personal jurisdiction over Defendant because Defendant currently transacts business in the Clarksburg Division of the Northern District of West Virginia. Defendant and its member institutions conduct athletic competitions, ticket and merchandise sales, television agreements, and other revenue-generating activities in the Northern District of West Virginia.

12. Venue is proper in this district under section 12 of the Clayton Act, 15 U.S.C. 22, and under 28 U.S.C. 1391(b)(2).

The Parties

13. The Attorneys General of the Plaintiff States bring this action in their quasi-sovereign capacities as the chief law enforcement officers of their respective states.

14. Plaintiff States have quasi-sovereign interests in protecting their citizens, including but not limited to college athletes and the consumers of college athletics, from economic harm and in ensuring that their economies

and the labor markets therein are not suppressed by unjustified restraints of trade.

15. The Plaintiff States are granted authority to bring actions for injunctive relief under federal antitrust law pursuant to 15 U.S.C. 26.

16. The United States brings this action pursuant to section 4 of the Sherman Act, 15 U.S.C. 4, to prevent and restrain NCAA from violating section 1 of the Sherman Act, 15 U.S.C. 1.

17. Defendant NCAA is an unincorporated association that acts as the governing body of college sports. The NCAA includes more than 1,000 member colleges and universities throughout the United States, including institutions in each of the Plaintiff States. These member institutions are organized into three divisions, and Division I includes over 350 schools. Through the NCAA Constitution and Bylaws, the NCAA and its members have adopted regulations governing all aspects of college sports, including specifically, the Bylaw at issue in this case, Division I Bylaw 14.5.5.1. The NCAA Constitution and Bylaws were adopted by votes of the member institutions and various NCAA councils, and they may be amended by votes of the member institutions or NCAA councils. Thus, the rules set forth in the NCAA Constitution and Bylaws constitute horizontal agreements between the NCAA and its member institutions and among NCAA member institutions.

18. As a practical matter, an academic institution that wishes to participate in any meaningful way in the highest and most popular level of collegiate athletics must maintain membership in the NCAA and abide by the Division I rules and regulations promulgated by the NCAA and its members. Failure to abide by these rules and regulations risks subjecting sports programs at the academic institution to punitive measures from the NCAA that include reduced athletic-scholarships, suspensions, prohibition on post-season eligibility, vacating previously-earned wins, monetary fines, and the so-called "death penalty."

19. The NCAA and its member institutions control the highest and most popular level of collegiate athletics. Therefore, any individual who wishes to provide athletic services in exchange for the payment of partial or full tuition for an undergraduate academic education and wishes to derive the substantial benefits from competing at the highest level of collegiate athletics must by necessity attend an NCAA Division I member institution.

20. There are zero practical alternatives that can provide the unique combination of attributes offered by Division I NCAA athletic schools: (i) the ability to exchange athletics services for the payment of the partial or full cost of an education plus room and board, (ii) high quality academic educational services, (iii) top-of-the-line training facilities, (iv) high quality coaches that will best be able to launch players to professional careers, (v) national publicity through national championships and nationwide broadcasting contracts, (vi) opportunities to profit from name, image, and likeness (“NIL”) agreements, and (vii) competition at the highest level of collegiate athletics.

Background

The Transfer Eligibility Rule, NCAA Bylaw 14.5.5.1

21. The NCAA and its member institutions are organized under a constitution and divided into three divisions. NCAA, Division I 2023–24 Manual, 3 (accessed Nov. 2, 2023), <https://web3.ncaa.org/lstdbi/reports/getReport/90008>, included in this filing as Exhibit A. Each of the NCAA’s three divisions has the authority to determine its own governing structure and membership. *Id.* at 5. The NCAA is overseen by a Board of Governors which appoints the President to administer the Association and “implement directions of the Board of Governors and divisional leadership bodies.” *Id.* at 4. Each member institution is required to “hold itself accountable to support and comply with the rules and principles approved by the membership.” *Id.* at 9.

22. Each NCAA division maintains its own legislative process for adopting bylaws, with some bylaws applying to only one division and others applying across divisions. *Id.* at 14. Proposed bylaw changes that move through the divisional legislative process within an “area of autonomy” as identified by the bylaws are adopted by certain conferences and their member institutions. *Id.* at 15. Federated legislation—changes that are applicable only to the adopting division—can be made by the Division I Council. *Id.* at 17. The Division I Council is comprised of representatives from member institutions and conferences. *Id.* at 396–397. Member institutions can propose amendments to the bylaws for the Division I Council’s review and can comment on proposed amendments under consideration. *Id.* at 17–18.

23. NCAA Bylaw 13.1.1.3.1 provides that for undergraduate college athletes that wish to transfer to a new member

institution, the college athlete must provide notice to the current institution during a specified period for the college athlete’s given sport. *Id.* at 75–76. After notification of intent to transfer, the current institution must “enter the [college athlete’s] information into the national transfer database,” a process known as the NCAA Transfer Portal. *Id.* at 75. According to a recent NCAA statement, 21,685 college athletes had entered the transfer portal in 2023 as of September 12. *DI Board Statement Regarding Transfer Waivers*, NCAA (Sept. 12, 2023), available at: <https://www.ncaa.org/news/2023/9/12/media-center-di-board-statement-regarding-transfer-waivers.aspx>.

24. NCAA Bylaw 14.5.5.1, herein referred to as the Transfer Eligibility Rule, states, “A transfer student from a four-year institution shall not be eligible for intercollegiate competition at a member institution until the student has fulfilled a residence requirement of one full academic year (two full semesters or three full quarters) at the certifying institution.” Exhibit A at 165. This rule does not prevent a college athlete from practicing or participating in other team activities during this one-year waiting period, only from competing on gameday. *Id.* One exception to this rule found in NCAA Bylaw 14.5.5.2.10 exempts college athletes transferring for the first time from the Transfer Eligibility Rule. *Id.* at 167. NCAA Bylaw 12.8.1 provides that college athletes have five calendar years to complete their four seasons of eligibility in any one sport. *Id.* at 55.

25. The NCAA Bylaws contain what is commonly known as the “Rule of Restitution,” which provides:

If a student-athlete who is ineligible under the terms of the bylaws or other legislation of the Association is permitted to participate in intercollegiate competition contrary to such NCAA legislation but in accordance with the terms of a court restraining order or injunction operative against the institution attended by such student-athlete or against the Association, or both, and said injunction is voluntarily vacated, stayed or reversed or it is finally determined by the courts that injunctive relief is not or was not justified, the Board of Directors may take any one or more of the following actions against such institution in the interest of restitution and fairness to competing institutions:

(a) Require that individual records and performances achieved during participation by such ineligible student-athlete shall be vacated or stricken;

(b) Require that team records and performances achieved during participation by such ineligible student-athlete shall be vacated or stricken;

(c) Require that team victories achieved during participation by such ineligible student-athlete shall be abrogated and the

games or events forfeited to the opposing institutions;

(d) Require that individual awards earned during participation by such ineligible student-athlete shall be returned to the Association, the sponsor or the competing institution supplying same;

(e) Require that team awards earned during participation by such ineligible student-athlete shall be returned to the Association, the sponsor or the competing institution supplying same;

(f) Determine that the institution is ineligible for one or more NCAA championships in the sports and in the seasons in which such ineligible student-athlete participated;

(g) Determine that the institution is ineligible for invitational and postseason meets and tournaments in the sports and in the seasons in which such ineligible student-athlete participated;

(h) Require that the institution shall remit to the NCAA the institution’s share of television receipts (other than the portion shared with other conference members) for appearing on any live television series or program if such ineligible student-athlete participates in a contest selected for such telecast, or if the Board of Directors concludes that the institution would not have been selected for such telecast but for the participation of such ineligible student-athlete during the season of the telecast; any such funds thus remitted shall be devoted to the NCAA postgraduate scholarship program; and

(i) Require that the institution that has been represented in an NCAA championship by such a student-athlete shall be assessed a financial penalty as determined by the Committee on Infractions.

Id. at 66–67. This rule allows the NCAA to punish college athletes and their member universities for actions taken in accordance with court orders if those orders are later revoked. *Id.*

26. Because of the commercial nature of the transactions between college athletes and NCAA member institutions and the effect these transactions have on college athletes and the consumers of college athletics, the NCAA’s enforcement of the Transfer Eligibility Rule falls within the purview of the Sherman Act. The Transfer Eligibility Rule’s anticompetitive effects within the sport-specific markets for the labor of NCAA Division I college athletes far outweigh the pretextual procompetitive benefits, and the Rule is an unreasonable restraint of trade that cannot survive rule of reason analysis.

Relevant Markets

27. Within NCAA Division I athletics, the Transfer Eligibility Rule affects two broad categories of labor markets: (1) athletic services in men’s and women’s Division I basketball and football bowl subdivision (“FBS”) football, wherein each college athlete participates in his or her sport-specific market, and (2)

athletic services in all other men's and women's Division I sports, wherein each athlete participates in his or her sport-specific market. Within these markets, college athletes compete for spots on NCAA Division I member institution athletic teams, while the NCAA member institutions simultaneously compete to secure elite-level college athletes. In so doing, the NCAA member institutions secure the labor of these college athletes through in-kind benefits—specifically, scholarships, academic programs, access to modern training facilities, and knowledge and training from premier coaching staffs.

28. The relevant geographic market is the United States. The NCAA and its member institutions are located across the country, and they engage in on-field competition and competition in the relevant labor markets throughout the United States.

29. Participation in NCAA Division I athletic events on gameday significant benefits to a college athlete. College athletes can showcase their skill in front of national audiences, gain exposure to professional team scouts, and compete against other college athletes at the highest level of collegiate athletics. In addition, the recent advent of NIL agreements presents college athletes the opportunity to benefit financially—sometimes in the millions of dollars—while playing college sports.

30. As mentioned above, there are no practical alternatives to the Division I level of NCAA athletics for college athletes who seek to market and showcase their elite-level skills. The benefits that come with participation in NCAA Division I athletics include the ability to exchange athletics services for (i) the payment of the partial or full cost of an education plus room and board, (ii) high quality academic educational services, (iii) top-of-the-line training facilities, (iv) high quality coaches that will best be able to launch players to professional careers, (v) national publicity through national championships and nationwide broadcasting contracts, (vi) opportunities to profit from NIL agreements, and (vii) competition at the highest level of collegiate athletics.

31. Within these relevant markets, the NCAA maintains exclusive power, dictating the rules and regulations for participation in Division I athletics through the Division I Council and NCAA member institutions.

32. Although the NCAA is a non-profit organization, the transactions that member institutions make with college athletes yield significant financial revenue for the member institutions and have significant effects on the future

earning potential of those college athletes. Namely, these transactions include partial or full scholarships in exchange for the college athlete's services. The college athletes, in return, receive the means to develop, refine, and showcase their skills—essential inputs to their future earning potential. NCAA athletic events in which these college athletes compete are marketed to consumers who view both in-person and via broadcasts of these sporting events, yielding significant revenue to the NCAA's member institutions and conferences. Accordingly, the transactions between these member institutions and the college athletes are inherently commercial in nature and fall under the purview of the Sherman Act.

Anticompetitive Effects

33. The NCAA enacts and enforces rules that it claims promote the well-being of college athletes and preserve the amateurism aspect of Division I college sports.

34. The NCAA and its member institutions adopt these rules through the member institutions and the Division I Council, making these rules equivalent to horizontal agreements among the NCAA and its member institutions who compete against one another for the labor of Division I college athletes.

35. Despite what the NCAA may claim, the Transfer Eligibility Rule restrains college athletes from freely moving among member institutions to improve their economic opportunity, personal growth, and well-being, a freedom afforded to other students at NCAA member institutions but not to college athletes. This restriction violates the Sherman Act because it has direct anticompetitive effects that harm college athletes and consumers of college athletics.

The Transfer Eligibility Rule's Effects on College Athletes

36. College athletes compete within the relevant markets of their respective sports for scholarships at NCAA Division I member institutions. Within these markets, college athletes are harmed by the Transfer Eligibility Rule. Effectively, the Transfer Eligibility Rule operates as a no-poach, market allocation agreement among the NCAA and its member institutions for the labor of NCAA Division I college athletes. The Transfer Eligibility Rule harms college athletes in three main areas of the relevant markets: (1) when college athletes are making the decision on whether to transfer, (2) when college athletes decide to transfer and are searching for a new institution to attend,

and (3) when college athletes are denied eligibility to compete for one year after transferring to a new institution.

37. First, the Transfer Eligibility Rule harms college athletes by discouraging them from transferring to a different institution that may benefit their academic, mental, and athletic well-being. Because of the Transfer Eligibility Rule, college athletes are denied the freedom of choice among Division I schools once they have competed on behalf of a given school. They are prevented from competing at a school to which they might choose to transfer for an entire year, denying them the benefits of competing in NCAA athletic events. This equates to a 20% loss of the time given to them to complete their seasons of eligibility and compete in the highest level of collegiate athletics.

38. With the threat of a year of ineligibility looming over transfer decisions, college athletes may hesitate to transfer even when a different institution may offer a situation that is better for the college athlete than the situation at the current institution. College athletes, just like non-athlete college students, may desire to transfer schools for any number of reasons. Distance from family, struggles with mental health, or better academic or athletic opportunities elsewhere are just a few of the many reasons college athletes may seek a transfer. The Transfer Eligibility Rule creates friction in the relevant markets by deterring college athletes from exploring better options within their sport-specific market.

39. Second, the Transfer Eligibility Rule affects college athletes in the relevant markets by artificially disadvantaging second-time transfers. Just like college athletes compete within the relevant markets for scholarship positions on Division I athletic teams, NCAA member institutions compete against each other to attract and retain elite college athletes to compete on the institutions' athletic teams. Second-time transferring college athletes are not able to apply for a waiver of the Transfer Eligibility Rule until after they have been accepted and enrolled at their new institution. Because the waiver process is discretionary and has been inconsistently applied, member institutions that accept a second-time transfer risk that the college athlete might not be eligible to compete for an entire academic year. This distorts the market by artificially deflating the value of a second-time transfer.

40. In some instances, college athletes may have no choice but to transfer or risk losing a scholarship at their current institution. Head coaches can

essentially force a player into the transfer portal by threatening to cut a player and revoke their scholarship, making the choice to transfer no real choice at all. In such situations, college athletes that have already transferred once, making them unqualified for the first-time transfer exception, must face the consequences of the Transfer Eligibility Rule despite having no control over the situation at their current institution. Such situations force college athletes into a transfer market where, compared to transfers who qualify for the first-time exception, they face an artificial competitive disadvantage because of the Transfer Eligibility Rule.

41. Third, the Transfer Eligibility Rule harms college athletes transferring a second time by denying them the opportunity to compete in NCAA Division I athletic events for an entire academic year after transferring to a new institution. NCAA Division I sports are the pinnacle of college athletics in the United States. Competing at this high level of athletics comes with immeasurable opportunities for personal, professional, and economic growth. For athletes seeking to continue competing professionally after college, NCAA Division I sports provide a platform to showcase athletic skills in front of national audiences and professional scouts. The Transfer Eligibility Rule unjustifiably denies these benefits to affected student athletes for an entire academic year.

42. The NCAA has often noted the importance of its college athletes' opportunities to compete at the highest level. See, e.g., *The Value of College Sports*, NCAA (last visited Nov. 10, 2023), <https://www.ncaa.org/sports/2014/1/3/the-value-of-college-sports.aspx> (where the NCAA expressly notes that the value of college sports to its college athletes includes unparalleled exposure and experiences through "the opportunity to travel across the country and around the world for regular-season contests, NCAA championships and foreign tours," which "can open doors for the few who will compete professionally and for the majority who will go pro in something other than sports.").

43. While college athletes subject to the Transfer Eligibility Rule's restrictions are allowed to practice and participate in other team activities, they are expressly restricted from competing in their sport. Practicing with one's teammates and competing on gameday are not the same thing. Competition is fundamentally different. Even the NCAA's public statements support this point:

NCAA tournaments are where dreams are fulfilled, lifelong memories are made and communities come together under a shared love for the game. Seeing college athletes, both in victory and defeat, competing with passion and conviction wins our hearts long after the clock hits zero. Simply put, championships represent the very best of college athletics.

This deserves to be felt at every juncture. Transformation Committee members evaluated differences that exist across sports to find ways to improve equity and bring these experiences closer together. *We recognized that championships are the pinnacle of a [college athlete's] Division I experience and sought to grant greater access to championships for well-qualified teams while honoring the existing structure for entry.* For travel to championships, our goal was to create new, elevated recommendations so teams and college athletes would have a comparable experience when traveling, regardless of sport or gender.

NCAA, *NCAA Division I Transformation Committee Final Report*, 14 (Jan. 3, 2023), https://ncaaorg.s3.amazonaws.com/committees/d1/transformation/Jan2023D1TC_FinalReport.pdf (where Lynda Tealer, a member of the Division I Transformation Committee and executive associate athletics director at the University of Florida, reemphasized the importance of competition at the highest level) (emphasis added).

44. Moreover, college athletes' opportunities to show the world the fruits of their labor occur on fields, courts, and rinks where the NCAA has unlawfully restricted their participation. Forced ineligibility and missing even a single game can negatively impact a college athlete's future earning potential. National television broadcasts provide significant exposure for college athletes. One game can take a college athlete from a local fan favorite to a household name. When even the slightest differences among players can affect positioning and earning potential in professional league drafts, every game is vital for college athletes and can significantly impact their future earning potential.

45. Apart from future earning potential, the Transfer Eligibility Rule impairs college athletes' ability to take advantage of current and future opportunities derived from their name, image, and likeness. NIL agreements may vary depending on the school at which an athlete competes (and the NIL-related resources a school might provide), the degree of exposure that the athlete might expect from playing sports at that school, the relationships a given school might have with third parties interested in entering NIL agreements (through collectives or otherwise), and ties to established media markets in which NIL agreements may be more

prevalent, among other factors. By limiting eligibility for affected college athletes, the Transfer Eligibility Rule prevents these college athletes from maximizing NIL valuations, which can run into the millions of dollars. The Transfer Eligibility Rule's restrictions for an entire academic year can have immeasurable and lasting economic effects on college athletes.

46. In addition to the potential economic effects on these college athletes and the dramatic impact these restraints have on the college athletes' overall collegiate athletics experience, the NCAA's denial of college athletes' ability to compete immediately through enforcement of the Transfer Eligibility Rule has caused negative impacts on the mental health and overall well-being of some college athletes.

47. There are numerous college athletes whose academic and athletic aspirations are being unlawfully restrained by the Transfer Eligibility Rule; the NCAA, media, and consumers of college athletics are well aware of this issue as evidenced by recently publicized examples of college athletes harmed by the Transfer Eligibility Rule.

RaeQuan Battle

48. RaeQuan Battle is a member of the West Virginia University ("WVU") Men's Basketball Team. Before joining WVU, he played basketball at the University of Washington for the 2019–20 and 2020–21 basketball seasons. Thereafter, he transferred to Montana State University ("MSU") and played there during the 2021–22 and 2022–23 basketball seasons.

49. Because Mr. Battle had transferred on a prior occasion, his ability to transfer to WVU from MSU for the 2023–24 basketball season was restricted by the Transfer Eligibility Rule. Thus, to be eligible to play immediately, he needed to have a waiver approved by the NCAA. WVU applied for him to receive a waiver for immediate eligibility, as he and WVU believed that his circumstances fit within the NCAA's criteria for waiver requests.

50. However, the NCAA recently denied his appeal for immediate eligibility at WVU. Mr. Battle is completely devastated by the NCAA's decision to deny him eligibility for the 2023–24 basketball season. Losing his coach at MSU, which prompted his decision to transfer to WVU, is a situation that he had no control over and severely affected his mental health. The denial of competition only exacerbates this impact to his mental health and overall well-being.

51. WVU is scheduled to play 31 regular season games during the 2023–2024 season. Mr. Battle is currently on the bench and has been unable to play in six competitive games thus far this season because of the Transfer Eligibility Rule. If he continues to be kept out of competition through December, then that would mean missing seven additional games (a total of 13 competitive games, which is almost half of the regular season schedule). Once these games have been played, they are gone forever. They will not be replayed in the future, and opportunities for development, exposure, and joy from participating in these contests are lost for Mr. Battle. Every passing game missed further irreparably harms Mr. Battle.

52. Not participating in competitive games significantly impacts Mr. Battle's ability to pursue NIL compensation and for his chances to pursue a career in professional basketball.

Jarrett Hensley

53. Jarrett Hensley is a member of the Southern Illinois University ("SIU") Men's Basketball Team. Before joining SIU, Mr. Hensley played at the University of North Carolina Greensboro ("UNCG") until deciding to transfer to the University of Cincinnati ("UC"). Because the coach who recruited him to UNCG chose to leave UNCG for UC, Mr. Hensley made the decision to follow his coach to UC. While this was a difficult decision, Mr. Hensley's coach was the only real connection he had to UNCG, so he and his family felt that following his coach to UC was the right decision.

54. The adjustment to basketball and school at UC was extremely difficult for Mr. Hensley, and he began to feel very depressed and anxious. After UC made the move to the Big 12 Conference, the level of competition and the amount of pressure Mr. Hensley put on himself only increased, as the pressure to win increased tremendously. As the coaches and staff started putting more emphasis on outcomes instead of focusing on his collegiate athlete experience, UC staff encouraged Mr. Hensley to enter the transfer portal, and he felt that it was necessary to transfer somewhere closer to home and to family.

55. Mr. Hensley feels like SIU coaches promote a family environment that makes him feel comfortable. As he knew he could make an impact and play on the SIU team, SIU was the right place for him as a student and athlete.

56. Mr. Hensley worked with the UC compliance staff in preparation to file for a waiver of the Transfer Eligibility Rule, who assured him that he would be immediately eligible upon transferring. As such, when Mr. Hensley made the decision to enter the transfer portal, he was convinced that he would be able to play immediately at his new school.

57. However, on the first day of school, SIU's coach had a meeting with Mr. Hensley to let him know that his waiver was denied. He was shocked, upset, and emotional. Being new to the school and having basketball taken from him led to stress and anxiety. There would be many nights that he didn't sleep at all. It made him question if he even wanted to continue playing, and he even had conversations with his coaches about potentially quitting the sport.

58. Mr. Hensley ultimately decided to stay at SIU and see the waiver the process through. The process and the decision looms over him every day. He struggles knowing that his season is in the hands of someone else and that he cannot do anything about it.

59. If unable to compete for the 2023–2024 season, Mr. Hensley will miss 31 games plus any postseason contests. Many of these games will be televised. On December 5, 2023, Mr. Hensley was forced to sit out the first SIU home basketball game against a Power 5 conference opponent since 2007. Mr. Hensley knows he could have helped his team win that nationally televised game, but because of the transfer Eligibility Rule, he did not get the opportunity to compete in that contest. He also missed out on the media coverage that could have helped him with potential NIL opportunities.

Noah Fenske

60. Noah Fenske is currently a member of the football team at SIU. He started his collegiate career at the University of Iowa on a football scholarship.

61. Mr. Fenske left Iowa due to mental health concerns and decided to transfer

to the University of Colorado. While at Colorado, he dealt with mental health issues and sought counseling, as the environment at Colorado was difficult and the school transitioned through more than one coaching staff while he was on the team.

62. The new coach at Colorado made it clear that current players were not going to be welcomed back after spring practices, and as such, Mr. Fenske had no choice but to look to transfer again in order to keep his scholarship.

63. Mr. Fenske was advised that if he transferred to a lower-level school, he would be eligible, even if he was transferring for a second time. Despite receiving offers to play from Power 5 conference teams, he entered the transfer portal hoping to find a place like SIU where he could play football and finish his degree. He would not have transferred if he had not been pushed into the decision and told that he would be able to play immediately. He wanted to finish his degree at Colorado and was only one year away, but when he was told that he would not have a scholarship, he had no choice but to find another school.

64. After arriving at SIU under the assumption he would be immediately eligible, Mr. Fenske was subsequently made aware that there had been a rule change, and that a waiver would have to be filed with the NCAA for immediate eligibility based on mental health struggles. To apply for this waiver, Mr. Fenske was forced to relive and relate to the NCAA the difficult circumstances that led to his mental health struggles.

65. Mr. Fenske had many coaches tell him he was good enough to enter the draft after the season, but as Mr. Fenske did not get to compete, no one had the opportunity to assess his talent. In total, he missed 11 regular season and two FCS Playoff games during the Fall 2023 season. Since his team was eliminated from the playoffs, Mr. Fenske wonders every day if he could have made a difference in that loss. Instead, the forced ineligibility from the Transfer Eligibility Rule negatively impacted his ability to play professional football, his ability to earn NIL money, and his mental health.

66. The NCAA's willingness to apply the Transfer Eligibility Rule despite the negative mental health consequences suffered by college athletes because of the Rule flies in the face of the lip-service that the NCAA has proudly given to its commitment to understanding and addressing college athletes' mental health concerns. See, e.g., Michelle Brutlag Hosick, *NCAA President Charlie Baker Lays Out Agenda for Growth, Transformation with Focus on Serving Student-Athletes*, NCAA (Aug. 2, 2023, 11:00 a.m.), <https://www.ncaa.org/news/2023/8/2/media-center-ncaa-lays-out-agenda-for-growth-transformation-with-focus-on-serving-student-athletes.aspx> (where the NCAA's national office, just months ago, reaffirmed its guidance to "[p]rovide a world-class athletics and academic experience for [college athletes] that fosters lifelong well-being."); see also Charlie Henry, *Social Series Highlights Importance of Mental Health Resources and Education*, NCAA (May 5, 2022, 11:26 a.m.), <https://www.ncaa.org/news/2022/5/25/media-center-social-series-highlights-importance-of-mental-health-resources-and-education.aspx#:~:text=The%20NCAA%20has%20developed%20several,mental%20health%20needs%20of%20their> ("NCAA has developed several educational resources, including 'Mental Health Best Practices: Understanding and Supporting Student-Athlete Mental Wellness,' [a] resource . . . designed with input from a diverse group of member and industry voices to help schools support and address the mental health needs of their [college athletes]."); see also Sports Science Institute, *Mental Health*, NCAA, <https://www.ncaa.org/sports/2021/2/10/sport-science-institute-mental-health.aspx> (last visited Nov. 10, 2023) (where the NCAA discusses educational resources, best practices for campuses, data and research, and summits and task forces, which all seek to address the importance of safeguarding college athletes' mental health and where the NCAA states that "[m]ental health [is a part of athlete health and] exists on a continuum, with resilience and thriving on one end of the spectrum and mental health disorders that disrupt a [college athlete's] functioning and performance at the other.").

67. The Transfer Eligibility Rule harms college athletes at every point in the transfer process and for the entire academic year where the Rule forces affected college athletes to watch from the sidelines and forego the benefits of competing in NCAA athletic events. The Rule's chilling effect on transfer

decisions can discourage college athletes from seeking the environment that is most beneficial to their well-being, and the Rule can limit the choices a college athlete has when transferring by competitively disadvantaging them when seeking a new school. Beyond the transfer process itself, the Rule prevents affected college athletes from realizing the significant benefits that come from competing in NCAA athletic events that are available only through competing on gameday. Thus, the Transfer Eligibility Rule harms college athletes in the relevant markets.

The Transfer Eligibility Rule's Effects on Consumers

68. The Transfer Eligibility Rule has downstream effects for consumers who attend NCAA athletic events in-person and for consumers who watch the events on television or listen on the radio. When the Transfer Eligibility Rule prevents college athletes from competing at their new institution after transferring, the Rule can decrease fan interest in a team's season by making popular players ineligible for competition and decreasing a team's competitiveness on gameday.

69. Furthermore, the Transfer Eligibility Rule is a barrier to increased parity in college athletics that would create a better product for consumers. By discouraging transfers through the academic year in residence requirement, the Transfer Eligibility Rule benefits larger and historically successful sports programs by allowing them to retain talented players on their depth charts who may otherwise wish to transfer and may be better served by transferring to another institution. Similarly, programs outside of the traditional upper echelon of college athletics would benefit from an environment without the Transfer Eligibility Rule, as it would allow them to enroll such transferring college athletes and have them compete in their athletics program. This, in turn, would lead to more parity within college athletics. A more level playing field of talent among Division I institutions creates a more compelling product for consumers of college athletics, and the Transfer Eligibility Rule stifles this increase in parity. The Transfer Eligibility Rule harms consumers of college athletics by making teams less competitive while affected college athletes are ineligible for an entire academic year and by preventing increased parity in college athletics that would create a more compelling product for consumers.

The Rule of Restitution and Its Impact on College Athletes and NCAA Division I Institutions

70. The Rule of Restitution, NCAA Bylaw 12.11.4.2, in a nutshell, provides that, if a plaintiff obtains an injunction against the unlawful conduct of the NCAA, and a college athlete and his or her member institution conduct themselves in conformity with that injunction, the NCAA may impose draconian punishments on both the athlete and the institution if the injunction is "vacated, stayed or reversed or it is finally determined by the courts that injunctive relief is not or was not justified." Exhibit A at 66–67.

71. The breadth of the Rule of Restitution is staggering and goes well beyond final adjudication on the merits in the NCAA's favor. For example, a college athlete could obtain a preliminary injunction to play during his final year of eligibility and, once the season is over, not wish to incur the cost and effort of continuing to litigate and instead wish to voluntarily dismiss. Alternatively, a court could determine that the athlete's eligibility had ended and the case was thereby mooted, resulting in dismissal. In both instances, the NCAA could impose harsh penalties in retaliation against the college athlete and the athlete's school even though the only court to consider the issue had ruled in the college athlete's favor.

72. Knowing this, many universities will not permit college athletes who challenge NCAA rules in court to compete, even if a court issues a temporary restraining order or preliminary injunction finding that those rules are likely illegal. This, in turn, deters college athletes from challenging the NCAA's substantive eligibility rules, such as the Transfer Eligibility Rule.

73. The Rule of Restitution's purpose and effect is to deter challenges to the NCAA's anticompetitive rules by attempting to deprive courts of the ability to grant effective relief and depriving individual college athletes and member universities of the practical ability to rely on court orders in their favor. Thus, the Rule of Restitution is itself a means of preventing defection from the anticompetitive agreement by member schools and of weaponizing the delay inherent in the litigation process to deter college athletes from mounting challenges to the antitrust merits of the NCAA's rules.

74. For any relief granted by this Court during the pendency of this case or on the merits to be effective, this Court must enjoin the NCAA from enforcing the Rule of Restitution against

college athletes and NCAA member institutions in retaliation for compliance with orders from this Court. Absent relief enjoining the Rule of Restitution, schools still may not allow college athletes ineligible under the Transfer Eligibility Rule to play for fear of future retaliation by the NCAA.

75. Because of the Rule of Restitution, college athletes run the risk of severe personal punishment and the risk of subjecting their schools or teammates to the harsh sanctions of the Rule of Restitution simply by following the terms of a court order. The rule amounts to the NCAA effectively deciding for itself the rules of interim relief rather than the courts. This deprives college athletes of the practical ability to rely on a court's temporary or preliminary injunctive relief in their favor. The Rule of Restitution is also a means of enforcing cartel-style discipline among the NCAA's member institutions, preventing defection, and manipulating rules of mootness to discourage challenges to the rules. For injunctive relief from this court to be effective, that relief must enjoin Defendant from punishing college athletes and member institutions under the Rule of Restitution simply for doing what a court of law prescribed for them to do.

Lack of Procompetitive Justifications

76. With the anticompetitive effects of the Transfer Eligibility Rule in the relevant markets described above, the burden must shift to Defendant under the rule of reason to provide procompetitive justifications for the Transfer Eligibility Rule. Despite what the NCAA could offer as justifications for the Rule, these justifications are pretextual and cannot outweigh the anticompetitive effects of the rule. Furthermore, the purported goals for the Transfer Eligibility Rule can be accomplished through less restrictive alternatives that are already present in the NCAA's bylaws.

The Transfer Eligibility Rule's Purported Justifications are Pretextual

77. The NCAA claims that bylaws such as the Transfer Eligibility Rule help college athletes maintain their academic progress and avoid falling behind due to the logistics and change that come with transferring schools. In addition, one purported justification for rules like the Transfer Eligibility Rule is that it promotes the NCAA's goal of preserving athletic amateurism, allowing it to widen consumer choice

through a unique product of amateur sports distinct from professional sports. However, both the text and the actual impact of the Transfer Eligibility Rule make these justifications pretextual.

78. Despite the NCAA's goal of promoting college athletes' academic well-being, the Transfer Eligibility Rule does not accomplish this goal and does not give college athletes additional time in their schedules to acclimate to a new campus environment. The Rule prevents college athletes from competing in NCAA athletic events for one academic year following a transfer. However, the Rule does not prevent those college athletes from participating in practices or other team activities during this year of ineligibility. Sitting out an entire season of practices and team workouts is not an option for college athletes who want to maintain their standing on a team. Thus, even under the restrictions of the Transfer Eligibility Rule, college athletes have no additional time in their schedules for increased attention to academics compared to their teammates who are eligible for competition except for a few hours on gameday when affected college athletes are forced to watch from the sidelines. Moreover, the NCAA does not limit the eligibility of freshman college athletes, whose transition from high school to college is far more arduous than that of a college athlete transferring between schools. Therefore, the Transfer Eligibility Rule does not promote the academic well-being of college athletes.

79. Furthermore, the Transfer Eligibility Rule does not support the goal of maintaining athletic amateurism in the NCAA. The NCAA has claimed in previous cases that the amateur nature of college athletics makes it uniquely appealing to consumers, as it distinguishes NCAA athletics from professional sports leagues. However, as a matter of law, supposed benefits in the market for watching college athletics cannot counterbalance harms the distinct, sport-specific markets for college athlete labor. See *Deslandes v. McDonald's United States, LLC*, 81 F.4th 699, 703 (7th Cir. 2023). Even if this cross-market balancing was appropriate, the Transfer Eligibility Rule has nothing to do with college athletes maintaining amateur status.

80. NCAA Bylaw 12.1.2 requires that Division I college athletes maintain amateur status to be eligible for NCAA competition. Exhibit A at 37. This bylaw states:

An individual loses amateur status and thus shall not be eligible for intercollegiate competition in a particular sport if the individual:

- (a) Uses athletics skill (directly or indirectly) for pay in any form in that sport;
- (b) Accepts a promise of pay even if such pay is to be received following completion of intercollegiate athletics participation;
- (c) Signs a contract or commitment of any kind to play professional athletics, regardless of its legal enforceability or any consideration received, except as permitted in Bylaw 12.2.5.1;
- (d) Receives, directly or indirectly, a salary, reimbursement of expenses or any other form of financial assistance from a professional sports organization based on athletics skill or participation, except as permitted by NCAA rules and regulations;
- (e) Competes on any professional athletics team per Bylaw 12.02.12, even if no pay or remuneration for expenses was received, except as permitted in Bylaw 12.2.3.2.1;
- (f) After initial full-time collegiate enrollment, enters into a professional draft (see Bylaw 12.2.4); or
- (g) Enters into an agreement with an agent.

Id.

81. By the definition the NCAA uses in its own bylaws, the Transfer Eligibility Rule does not affect anything related to a college athlete's amateur status. Allowing college athletes to practice all season with their teams but preventing them from competing on gameday does nothing to a college athlete's amateur status. The absence of the Transfer Eligibility Rule would do nothing to affect the amateur status of transferring college athletes. The Transfer Eligibility Rule does not serve the goal of preserving the NCAA's amateurism model nor does it help preserve the amateur status of college athletes, and the justifications for the Transfer Eligibility Rule are pretextual.

The Purported Goals of the Transfer Eligibility Rule Are Accomplished Through Less Restrictive Bylaws Already in Place

82. While the goals of the Transfer Eligibility Rule may be promoting the academic well-being of college athletes and preserving athletic amateurism within the NCAA, less restrictive alternatives already exist within the NCAA's regulatory structure that ensure that college athletes maintain progress towards college degrees and prevent college sports from becoming a free agent market like professional sports leagues.

83. NCAA Bylaws already require college athletes to maintain progress toward degrees to be eligible to compete in NCAA events. NCAA Bylaw 14.4.1 requires college athletes to “maintain progress toward a baccalaureate or equivalent degree at that institution” to be eligible for intercollegiate competition at their college or university. Exhibit A at 150–51. In addition, NCAA Bylaw 20.2.4.13 requires member institutions to publish their progress-toward-degree requirements for college athletes, thus making these requirements available to college athletes at each institution. *Id.* at 367. Other NCAA Bylaws require minimum credit hour and grade point averages for college athletes to be eligible for competition. *Id.* at 151, 154.

84. Further, NCAA Bylaws already prohibit in-season transfers within the same sport. Specifically, NCAA Bylaw 14.5.5.3 states,

A transfer student from a four-year institution who has received a waiver of or qualifies for an exception to the transfer residence requirement (per Bylaw 14.5.5.2) shall not be eligible for competition in which the [college athlete’s] performance could be used for NCAA championship qualification or consideration if the [college athlete] participated in competition at the previous four-year institution in the same sport in which the [college athlete’s] performance could have been used for NCAA championship qualification or consideration. *Id.* at 168.

85. These NCAA Bylaws setting minimum academic requirements and preventing in-season transfers already exist as less restrictive alternatives to achieving the goals of the Transfer Eligibility Rule. The academic eligibility requirements already in effect serve the goal of preventing college athletes from falling behind academically while still being eligible to compete in athletic events. If a college athlete fails to make adequate progress toward a degree or otherwise fails to meet minimum NCAA requirements, the student will be ineligible to participate in competition. The requirement that the member institutions provide college athletes with the progress-toward-degree requirements at each institution allows college athletes to adequately plan and know what will be required academically to maintain athletic eligibility.

86. Furthermore, preventing in-season transfers with immediate eligibility serves the goal of preserving athletic amateurism among NCAA college athletes. This rule prevents the kind of free agent movement among teams seen in professional sports leagues by preventing college athletes from leaving

mid-season either for participation on a higher-achieving team or in search of more playing time. These goals are accomplished without the unwarranted restrictions of the Transfer Eligibility Rule.

87. With the goals of the Transfer Eligibility Rule met by less restrictive alternatives already present in the NCAA’s Bylaws, the NCAA cannot justify imposing the restrictions of the Transfer Eligibility Rule on college athletes. Any purported benefits of the Transfer Eligibility Rule are far outweighed by the harm the rule inflicts on college athletes and consumers of college athletics. With less restrictive alternatives already in place, there is no justification for the NCAA to restrict the choices of college athletes in the relevant markets by enforcing the Transfer Eligibility Rule.

Count 1: Violation of Section 1 of the Sherman Act

88. Plaintiffs repeat and reallege each allegation set forth in the preceding paragraphs as if fully set forth herein.

89. Defendant NCAA, by and through its officers, directors, employees, agents or other representatives, and its member institutions have entered an illegal agreement to restrain and suppress competition in the relevant markets through the adoption and enforcement of the Transfer Eligibility Rule. Specifically, the NCAA and NCAA member institutions have agreed to unlawfully restrain the ability of Division I college athletes to transfer to other Division I schools without loss of athletic eligibility. The restraint imposed by the Transfer Eligibility Rule cannot withstand analysis under the rule of reason.

90. The markets for athletic services in men’s and women’s Division I basketball and football bowl subdivision (“FBS”) football and for athletics services in all other men’s and women’s Division I sports are relevant antitrust markets. The transactions between NCAA member institutions and college athletes in these markets are commercial in nature and fall under the purview of the Sherman Act.

91. This unlawful agreement among horizontal competitors has unreasonably restrained competition among schools for the college athletes competing in the relevant markets, as transferring college athletes potentially face a one-year waiting period before obtaining full eligibility to compete in NCAA athletic events at their new member institution. The threat of this one-year waiting period discourages transfers, disadvantages college athletes subject to this waiting period, and

prevents college athletes from realizing the benefits of competing in NCAA athletic events for an entire academic year.

92. Division I college athletes have been deprived of the benefits of free and open competition because of the Transfer Eligibility Rule. Furthermore, college athletes forced to wait a year prior to eligibility after transferring are deprived of the benefits that come from competition in NCAA Division I athletic events, harming these college athletes’ current and future earning potentials.

93. As a direct result of Defendant’s conduct, Division I college athletes and consumers of college athletics have suffered and continue to suffer antitrust injury due to the reduction in competition among Division I schools for college athletes through the restrictions imposed by the Transfer Eligibility Rule.

94. The Transfer Eligibility Rule yields few, if any, benefits to competition in Division I collegiate athletics to the NCAA’s member institutions, to college athletes, or to consumers of NCAA athletics contests. Any such benefits are far outweighed by the harm to competition and to the college athletes who are subject to the Transfer Eligibility Rule. Furthermore, the NCAA bylaws already contain less restrictive alternatives that accomplish the NCAA’s goals for the Transfer Eligibility Rule.

95. Defendant’s conduct is ongoing and will continue to impose injury on college athletes and consumers of college athletics unless injunctive relief is granted. This ongoing harm from the Transfer Eligibility Rule affects residents and the economies of the Plaintiff States by unreasonably restraining trade in labor markets for college athletics within the Plaintiff States and throughout the United States.

96. Defendant and its member institutions’ anticompetitive acts were intentionally directed at the United States market and had a substantial and foreseeable effect on interstate commerce.

Prayer for Relief

Wherefore, Plaintiffs respectfully request that this Court:

97. Adjudge and decree that Defendant’s enforcement of NCAA Bylaw 14.5.5.1 violates section 1 of the Sherman Act, 15 U.S.C. 1;

98. Enter a permanent injunction, in a form that the Court deems just and proper, pursuant to 15 U.S.C. 4 and 26, enjoining Defendant from continuing to violate section 1 of the Sherman Act by enforcing NCAA Bylaw 14.5.5.1 and from enforcing NCAA Bylaw 12.11.4.2

to punish college athletes and member institutions for actions taken in compliance with any orders from this Court;

99. Award to each Plaintiff its costs, including reasonable attorneys' fees; and

100. Order any other relief that this Court deems just and proper.

Dated: January 18, 2024

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**In the United States District Court for
the Northern District of West Virginia
Clarksburg Division**

State of Ohio, 30 E. Broad St., 26th
Floor, Columbus, OH 43215, Plaintiffs,
v. National Collegiate Athletic
Association, 700 W. Washington Street,
P.O. Box 6222, Indianapolis, IN 46206-
6222, Defendant.

Case No: 1:23-cv-00100

Judge Bailey

**EXHIBIT A TO AMENDED
COMPLAINT**

(Exhibit A is NCAA, Division I 2023-24
Manual, available at <https://web3.ncaa.org/lstdbi/reports/getReport/90008>)

**In the United States District Court for
the Northern District of West Virginia
Clarksburg Division**

State of Ohio, State of Colorado, State
of Illinois, State of Minnesota, State of
Mississippi, State of New York, State of
North Carolina, State of Tennessee,
Commonwealth of Virginia, State of
West Virginia, District of Columbia, and
United States of America, Plaintiffs, v.
National Collegiate Athletic
Association, Defendant.

Civil No. 1:23-cv-100

Judge John Preston Bailey

**[Proposed] Final Judgment and
Permanent Injunction**

1. *Whereas* the Plaintiff States of
Ohio, Colorado, Illinois, Minnesota,
Mississippi, New York, North Carolina,
Tennessee, and West Virginia; the
Commonwealth of Virginia; the District
of Columbia (collectively, “States”); and the

United States of America have
brought this action alleging violations of
the Sherman Act, 15 U.S.C. 1 *et seq.*,
against Defendant National Collegiate
Athletic Association (“NCAA”).

2. *Whereas* Plaintiff States, through
their respective Attorneys General, are
duly authorized to bring suits for
injunctive relief to enforce the Sherman
Act pursuant to 15 U.S.C. 1 and 26.

3. *Whereas* Plaintiff United States of
America is duly authorized to bring
suits for injunctive relief to enforce the
Sherman Act pursuant to 15 U.S.C. 1
and 4.

4. *Whereas* all parties consent to this
venue and to the personal jurisdiction of
the Court for purposes of this litigation,
entry of the Final Judgment, and any
subsequent litigation to enforce its
terms.

5. *Whereas* this Court has subject
matter jurisdiction over this action
under 15 U.S.C. 4 and 28 U.S.C. 1331
and 1337(a), and in the case of Plaintiff
United States, 28 U.S.C. 1345.

6. *Whereas* the NCAA’s member
institutions and conferences have
adopted rules and regulations governing
certain aspects of college sports.

7. *Whereas* NCAA Bylaw¹ 14.5.5.1,
herein referred to as the Transfer
Eligibility Rule, provides that certain
transfer students shall not be eligible for
intercollegiate competition in Division I
until they have fulfilled an academic
“year of residence” at their new
institution, unless they qualify for a
transfer exception or secure a waiver.

8. *Whereas* Plaintiffs allege that the
Transfer Eligibility Rule has
unreasonably restrained competition for
Division I student-athletes among
schools and has prevented them from
realizing the benefits of free and open
competition for their athletic services.

9. *Whereas* Plaintiffs allege that the
Transfer Eligibility Rule yields few, if
any, procompetitive benefits.

10. *Whereas* Plaintiffs allege that, as a
direct result of the NCAA’s conduct,
Division I student-athletes and
consumers of college athletics have
suffered and continue to suffer antitrust
injury due to the reduction in
competition among member institutions
for student-athletes’ services.

11. *Whereas* Plaintiffs therefore allege
that the Transfer Eligibility Rule is an
illegal agreement to restrain and
suppress competition in the nationwide
market for Division I student-athletes’
labor in intercollegiate athletics, in
violation of section 1 of the Sherman
Act.

12. *Whereas* NCAA Bylaw 12.11.4.2,
herein referred to as the Rule of
Restitution, provides that, if a student-
athlete obtains an injunction against the
NCAA, and the student-athlete and his
or her member institution conduct
themselves in conformity with that
injunction, the NCAA may nonetheless
impose certain penalties on both the
student-athlete and the member
institution if the injunction is ultimately
vacated, stayed, or reversed.

13. *Whereas* Plaintiffs allege that the
Rule of Restitution deters member
institutions from relying on court orders
finding that the NCAA’s rules are

¹ All references to “Bylaws” or “NCAA Rules” are
to the NCAA Division I 2023-24 Manual.

anticompetitive (or otherwise illegal) and, therefore, deprives courts of the ability to grant effective relief from violations of state and federal law.

14. *Whereas* Plaintiffs allege that for injunctive relief prohibiting enforcement of the Transfer Eligibility Rule to be effective, the NCAA must also be enjoined from enforcing the Rule of Restitution to punish member institutions or student-athletes who immediately participate in intercollegiate competition following a transfer.

15. *Whereas* following an evidentiary hearing, the Court entered a temporary restraining order and preliminary injunctive relief against the NCAA enjoining enforcement of the Transfer Eligibility Rule and the Rule of Restitution. Dkt. 39, 63.

16. *Whereas* Plaintiffs allege that absent permanent injunctive relief, Division I student-athletes will continue to suffer irreparable harm from the Transfer Eligibility Rule, whether by missing games that cannot be replayed, failing to secure name, image, and likeness (“NIL”) deals or professional opportunities that would otherwise be available, or foregoing transfer decisions they would otherwise pursue.

17. *Whereas* Plaintiffs allege that the balance of the equities favors issuing a permanent injunction, and issuance of a permanent injunction is in the public interest.

18. *Whereas* the United States and the NCAA have agreed to resolve this matter by entry of this Final Judgment.

Accordingly, it is *Hereby Ordered, Adjudged, and Decreed*:

19. The foregoing recitals are incorporated and made a part of this Final Judgment.

20. The NCAA shall take all steps necessary to comply with the Stipulation and Order entered by the Court.

21. This Final Judgment resolves only the United States’ claims with respect to the Transfer Eligibility Rule as applied to Division I student-athletes and does not affect other Bylaws or claims not made in this action. For the avoidance of doubt, this Final Judgment does not apply to any Bylaws of NCAA Division II or NCAA Division III nor does it resolve any antitrust claims regarding those rules.

22. The NCAA and any person or organization acting in concert with it (including but not limited to its officers, employees, staff, member institutions, councils, and committees), are permanently restrained and enjoined from:

a. enforcing the Transfer Eligibility Rule, NCAA Bylaw 14.5.5.1, or any

substantially similar rule requiring a Division I student-athlete to maintain a period of residence or otherwise refrain from competition solely because of a transfer between NCAA member institutions;

b. enforcing the Rule of Restitution, NCAA Bylaw 12.11.4.2, on any Division I member institution or student-athlete related to a student-athlete’s participation in intercollegiate competition following a transfer in reliance on this Court’s temporary restraining order or preliminary injunction or this Final Judgment;

c. taking any other action to retaliate against a Division I member institution for conduct related to the Transfer Eligibility Rule, including but not limited to (i) supporting a student-athlete who challenged the Transfer Eligibility Rule or (ii) permitting a student-athlete to compete during the period of this Court’s temporary restraining order or its preliminary injunction in reliance on those orders; and

d. taking any action to retaliate against any Division I student-athlete that transferred NCAA member institutions, including but not limited to those student-athletes who (i) challenged the Transfer Eligibility Rule, (ii) sought a waiver from the Transfer Eligibility Rule, or (iii) competed during the period of this Court’s temporary restraining order or its preliminary injunction in reliance on those orders.

23. The NCAA shall provide an additional year of eligibility to any Division I student-athlete who was deemed ineligible to compete for a season or any portion of a season of competition occurring during or since the 2019–20 academic year because of the Transfer Eligibility Rule provided the student-athlete:

a. transferred between two member institutions more than once;

b. is currently enrolled at a Division I member institution; and

c. is currently eligible to compete, or their eligibility expired at the end of a season of competition completed during the 2023–24 academic year.

For the avoidance of doubt, a Division I student-athlete described in this provision shall have no fewer than six calendar years to complete their four seasons of intercollegiate competition in any one sport (see NCAA Bylaw 12.8), instead of the five calendar years set forth under NCAA Bylaw 12.8.1.

24. For the purposes of determining or securing compliance with this Final Judgment or determining whether this Final Judgment should be modified or vacated, upon written request of

Plaintiffs and reasonable notice to the NCAA, the NCAA must:

a. permit, subject to legally recognized privileges, authorized representatives of Plaintiffs to inspect all books, ledgers, accounts, records, data, and documents in the possession, custody, or control of the NCAA relating to any matters contained in this Final Judgment;

b. permit, subject to legally recognized privileges, authorized representatives of Plaintiffs to interview, either informally or on the record, the NCAA’s officers, employees, or agents relating to any matters contained in this Final Judgment; and

c. submit written reports or respond to written interrogatories, under oath if requested, relating to any matters contained in this Final Judgment.

25. No information or documents obtained pursuant to this Final Judgment may be divulged by Plaintiffs to any person other than an authorized representative of Plaintiffs, except (a) in the course of legal proceedings to which the United States is a party, including grand-jury proceedings; (b) for the purpose of securing compliance with this Final Judgment; or (c) as otherwise required by law.

26. If the United States receives a request under the Freedom of Information Act, 5 U.S.C. 552, for disclosure of documents or information obtained pursuant to this Final Judgment, the United States will act in accordance with that statute and with all applicable Department of Justice regulations regarding the protection of confidential commercial information. When providing any documents or information to the United States pursuant to this Final Judgment, the NCAA should designate the confidential portions of such materials as provided by 28 CFR 16.7.

27. Within sixty (60) days of entry of this Final Judgment, the NCAA shall post a copy of this Final Judgment on its public website.

28. The NCAA shall not take any action, nor adopt any rules, by-laws or policies that have the effect of undermining or circumventing the provisions of this Final Judgment.

29. The Court will retain jurisdiction for purposes of enforcing this Final Judgment and resolving any dispute that may arise under it.

30. Plaintiff United States retains and reserves all rights to enforce the provisions of this Final Judgment, including the right to seek an order of contempt from the Court. The NCAA agrees that in a civil contempt action, a motion to show cause, or a similar action brought by the United States relating to an alleged violation of this

Final Judgment, the United States may establish a violation of this Final Judgment and the appropriateness of a remedy therefor by a preponderance of the evidence, and the NCAA waives any argument that a different standard of proof should apply. This Final Judgment should be interpreted to give full effect to the procompetitive purposes of the antitrust laws and to restore the competition Plaintiffs allege was harmed by the challenged conduct. The NCAA agrees that it may be held in contempt of, and that the Court may enforce, any provision of this Final Judgment that, as interpreted by the Court in light of these procompetitive principles and applying ordinary tools of interpretation, is stated specifically and in reasonable detail, whether or not it is clear and unambiguous on its face. In any such interpretation, the terms of this Final Judgment should not be construed against either party as the drafter.

31. In connection with a successful effort by the United States to enforce this Final Judgment against the NCAA, whether litigated or resolved before litigation, the NCAA agrees to reimburse the United States for reasonable fees and expenses incurred by its attorneys, as well as all other costs including experts' fees, reasonably incurred in connection with that effort to enforce this Final Judgment, including in the investigation of the potential violation.

Dated: _____, 2024

John Preston Bailey,
United States District Judge.

**In the United States District Court for
the Northern District of West Virginia
Clarksburg Division**

State of Ohio, State of Colorado, State of Illinois, State of Minnesota, State of Mississippi, State of New York, State of North Carolina, State of Tennessee, Commonwealth of Virginia, State of West Virginia, District of Columbia, and United States of America, Plaintiffs, v. *National Collegiate Athletic Association*, Defendant.

Civil No. 1:23-cv-100
Judge John Preston Bailey

Competitive Impact Statement

In accordance with the Antitrust Procedures and Penalties Act, 15 U.S.C. 16(b)–(h) (the “APPA” or “Tunney Act”), the United States of America files this Competitive Impact Statement related to the proposed Final Judgment here.¹

¹ The Plaintiff States and the NCAA have agreed to a parallel proposed Consent Judgment that would resolve the States' claims in this action.

I. Nature and Purpose of the Proceeding

The United States joined this action against Defendant National Collegiate Athletic Association (“NCAA”) on January 18, 2024, to remedy a violation of section 1 of the Sherman Act, 15 U.S.C. 1. section 1 of the Sherman Act prohibits “contract[s], combination[s], or conspirac[ies]” in restraint of trade or commerce.” 15 U.S.C. 1. The Sherman Act is designed to ensure “free and unfettered competition as the rule of trade. It rests on the premise that the unrestrained interaction of competitive forces will yield the best allocation of our economic resources, the lowest prices, the highest quality and the greatest material progress. . . .” *National Collegiate Athletic Ass’n v. Board of Regents of Univ. of Okla.*, 468 U.S. 85, 104 n.27 (1984) (quoting *Northern Pac. Ry. v. United States*, 356 U.S. 1, 4–1 (1958)).

The Amended Complaint alleges that the NCAA and its Division I members agreed to limit competition for student athletes. Former NCAA Bylaw 14.5.5.1 (the “Transfer Eligibility Rule”) unjustifiably restrained the ability of college athletes to engage in the market for their labor.³ The Transfer Eligibility Rule, which was in effect at the time the Amended Complaint was filed and is described in more detail below, imposed a one-year delay in the eligibility of certain college athletes transferring between NCAA member institutions and thus reduced competition in the labor market for college athletes. This rule increased the cost of student-athletes transferring to different institutions and made Division I institutions less interested in recruiting student athletes.

The Amended Complaint also alleges that NCAA Bylaw 12.11.4.2 (the “Rule of Restitution”) furthers the anticompetitive effects of certain eligibility rules by deterring college athletes from challenging those rules. Under that rule, the NCAA can punish college athletes (and their associated institutions) that bring a legal challenge against the NCAA’s eligibility rules and receive a court-ordered injunction barring enforcement of those rules, if the injunction is later overturned or stayed. Concurrently with filing the initial Complaint, Plaintiffs sought a temporary restraining order to enjoin Defendant

³ Plaintiffs State of Ohio, State of Colorado, State of Illinois, State of New York, State of North Carolina, State of Tennessee, and State of West Virginia filed the initial Complaint in this action on Dec. 7, 2023. Plaintiff United States, along with Plaintiffs Commonwealth of Virginia, District of Columbia, State of Minnesota, and State of Mississippi joined this action via an Amended Complaint filed on January 18, 2024.

from enforcing the Transfer Eligibility Rule and the Rule of Restitution. ECF No. 2.

The Court granted Plaintiffs’ request for a temporary restraining order, finding that Plaintiffs were likely to succeed on the merits and enjoining the NCAA from enforcing the Transfer Eligibility Rule and the Rule of Restitution. *Ohio v. National Collegiate Athletic Ass’n*, No. 1:23–CV–100, — F.Supp.3d—, 2023 WL 9103711 (N.D. W. Va. Dec. 13, 2023). The Court subsequently converted the temporary restraining order into a preliminary injunction upon agreement of the parties. ECF No. 63.

On April 17, 2024, the NCAA’s Division I Council voted to withdraw the Transfer Eligibility Rule, modifying its bylaws to allow players to freely transfer multiple times without a year-in-residence requirement. This change was approved by the NCAA’s Board of Governors on April 22, 2024. See *Division I Board of Directors ratifies transfer, NIL rule changes*, available at: <https://www.ncaa.org/news/2024/4/22/media-center-division-i-board-of-directors-ratifies-transfer-nil-rule-changes.aspx>.

The United States has now filed a proposed Final Judgment and Stipulation and Order, which are designed to ensure that the loss of competition alleged in the Amended Complaint is fully remedied and does not recur. Under the proposed Final Judgment, which is explained more fully below, the NCAA would be permanently enjoined from enforcing the former Transfer Eligibility Rule and prohibited from implementing similar rules in the future. The Stipulation and Order requires the NCAA to abide by and comply with the provisions of the proposed Final Judgment until the proposed Final Judgment is entered by the Court or until expiration of time for all appeals of any Court ruling declining entry of the proposed Final Judgment.

The United States and the NCAA have stipulated that the proposed Final Judgment may be entered after compliance with the APPA. Entry of the proposed Final Judgment will terminate this action, except that the Court will retain jurisdiction to construe, modify, or enforce the provisions of the proposed Final Judgment and to punish violations thereof.

II. Description of Events Giving Rise to the Alleged Violation

A. Defendant NCAA

Defendant NCAA is an unincorporated association that acts as the governing body of college sports.

Am. Compl. ¶ 17. The NCAA includes more than 1,000 member colleges and universities throughout the United States. *Id.* These member institutions are organized into three divisions, including Division I, which includes over 350 schools and allows for scholarships. *Id.* Division I schools compete with each other not only through athletic events but also in other upstream and downstream economic markets: for instance, NCAA Division I schools “compete against each other to attract television revenues,” *Board of Regents*, 468 U.S. at 99, and, at issue in this case, “compete fiercely” in the labor market “for student athletes.” *National Collegiate Athletic Ass’n v. Alston*, 594 U.S. 69, 86 (2021). Through the NCAA Constitution and Bylaws, the NCAA and its members have adopted regulations governing all aspects of college sports, including the Transfer Eligibility Rule. The NCAA Constitution and Bylaws are adopted by the votes of member institutions and various NCAA councils, and they may be amended by votes of member institutions or NCAA councils. Am. Compl. ¶ 17. Accordingly, the rules set forth in the NCAA Constitution are horizontal agreements between the NCAA and its member institutions and among NCAA member institutions. *Id.*

An academic institution that wishes to participate in any meaningful way in the highest and most popular level of collegiate athletics must maintain membership in the NCAA and abide by its Division I rules, regulations, and bylaws. Am. Compl. ¶ 18. Failure to abide by these rules puts academic institutions at risk of punitive measures from the NCAA that include, among other things, reduced athletic scholarships, prohibitions on postseason eligibility, vacating of previously earned wins, and monetary fines. *Id.* Because the NCAA and its member institutions have monopsony power in controlling the highest and most popular level of college athletics, any individual who wishes to provide athletic services in exchange for full or partial payment of undergraduate tuition as well as other substantial benefits gained from competing at the highest level of collegiate athletics must by necessity attend an NCAA Division I member institution and has no option but to abide by its rules. Am. Compl. ¶ 19.

Participation in NCAA Division I athletics offers college athletes unique opportunities that are not available elsewhere: (i) the ability to exchange athletics services for the payment of the partial or full cost of an education plus room and board, (ii) high quality

academic educational services, (iii) top-of-the-line training facilities, (iv) high quality coaches who will best be able to launch players to professional careers, (v) national publicity through national championships and nationwide broadcasting contracts, (vi) opportunities to profit from name, image, and likeness (“NIL”) agreements, and (vii) competition at the highest level of collegiate athletics. Am. Compl. ¶ 20.

B. Relevant Markets

Within NCAA Division I athletics, the Transfer Eligibility Rule affects labor markets for athletic services in men’s and women’s Division I sports, wherein each college athlete participates in his or her sport-specific market. *See* Am. Compl. ¶ 27. Within these markets, NCAA member institutions compete to attract and enroll elite-level college athletes. In so doing, NCAA member institutions secure the labor of these college athletes through in-kind benefits: specifically, scholarships, academic programs, access to modern training facilities, and training from premier coaches and their staff. *Id.*

Participation in NCAA Division I athletic competition confers significant and unique benefits to college athletes, such as the ability to showcase their skill before national audiences, gain exposure to professional team scouts, and compete against other elite college athletes. Am. Compl. ¶ 29. In addition, NIL agreements allow college athletes to benefit financially—sometimes for millions of dollars—from the aforementioned national exposure and elite competitive environment that NCAA Division I athletics provide. *Id.* There are no practical alternatives to NCAA Division I athletics for college athletes who seek these benefits. *Id.* at ¶ 30.

The relevant geographic market is the United States. NCAA member institutions are located across the country, and many college athletes are willing to enroll in schools far distant from home to pursue athletic opportunities. Therefore, those NCAA member institutions engage in competition in the relevant labor markets throughout the United States. Am. Compl. ¶ 28. Within the relevant geographic and labor markets, the NCAA maintains exclusive power, dictating the rules and regulations for participation Division I athletics through the Division I Council and NCAA member institutions. *Id.* at ¶ 32.

C. The Transfer Eligibility Rule

Under the Transfer Eligibility Rule, “[a] transfer student from a four-year institution shall not be eligible for

intercollegiate competition at a[n NCAA] member until the student has fulfilled a residence requirement of one full academic year (two full semesters or three full quarters) at the certifying institution.” Am. Compl. ¶ 23 (quoting *NCAA Division I 2023–24 Manual*, Am. Compl. Ex. A at 165). Although the Transfer Eligibility Rule was a default rule that applied to all transfers, a separate rule created an exemption for the first time a college athlete transfers; thus, the Transfer Eligibility Rule in effect applied only to the second time (or more) that a college athlete transferred schools. *Id.* While the Rule barred a college athlete from competing during this one-year waiting period, it did not exempt college athletes from all the other requirements and obligations—including practicing, traveling with the team, and other commitments—of being a college athlete. *Id.* Under NCAA Bylaw 12.8.1, college athletes have five calendar years to complete four seasons of competitive eligibility in any one sport. *See* Am. Compl. Ex. A at 55. Thus, this one-year waiting period removed 20% of the total time available for the college athlete to complete her athletic career. College athletes were thus forced to weigh the one-year ineligibility period against the potential benefits of moving to a better opportunity at another school. Am. Compl. ¶ 7. While the Rule provided for the possibility of a waiver of the ineligibility period, the granting of the waiver was at the discretion of the NCAA and only after the college athlete had already enrolled in a new school. In practice, those waivers were inconsistently and arbitrarily awarded, and, in any event, the uncertainty of the waiver process itself was a deterrent to transferring. Am. Compl. ¶ 39.

D. The “Rule of Restitution”

The NCAA Bylaws contain what is commonly known as the “Rule of Restitution,” which allows the NCAA to punish college athletes and their member institutions for actions taken in accordance with court orders if those orders are later revoked. Am. Compl. ¶ 25 (citing NCAA Bylaw 12.11.4.2, Am. Compl. Ex. A at 66–67). For example, under the Rule of Restitution, were a college athlete to challenge an NCAA bylaw preventing her participation, receive a court order enjoining the bylaw, and then go on to win a conference championship with her team that season, the school would be at risk of having its wins later vacated by the NCAA if the court’s order were reversed.

The obvious purpose and effect of the Rule of Restitution is to deter challenges

to the NCAA's anticompetitive rules by discouraging athletes from protecting themselves and thus trying to deprive courts of the ability to grant effective relief. Am. Compl. ¶ 73. Under the Rule of Restitution, college athletes run the risk of personal punishment and the risk of subjecting their schools or teammates to harsh sanctions simply by following the terms of a court order. *Id.* The Rule of Restitution grants the NCAA the ability to decide for itself the rules of interim relief rather than the courts. *Id.* Plaintiffs argued, and the Court agreed, that any injunctive relief against the Transfer Eligibility Rule would need to be paired with injunctive relief against the Rule of Restitution. Am. Compl. ¶ 74; *Ohio v. NCAA*, 2023 WL 9103711, at *11–12.

E. Anticompetitive Effects

The Transfer Eligibility Rule restrained college athletes from freely moving among member institutions to improve their economic opportunity, personal growth, and well-being, a freedom afforded to other students at NCAA member institutions but not to college athletes. The Transfer Eligibility Rule produced direct anticompetitive effects in the relevant markets in three phases of the college athlete transfer process: (1) when college athletes were deciding whether to transfer, (2) when college athletes decided to transfer and were searching for a new institution to attend, and (3) when college athletes were denied eligibility to compete for one year after transferring to a new institution. *Ohio v. NCAA*, 2023 WL 9103711, at *5.

In the first phase, when college athletes were deciding whether to transfer, the Transfer Eligibility Rule discouraged college athletes from transferring to a different institution that may benefit their academic, athletic, mental, and financial well-being. *Ohio v. NCAA*, 2023 WL 9103711, at *5. College athletes, just like non-athlete college students, seek to transfer schools for any number of reasons, including but not limited to better academic, athletic, or financial opportunities elsewhere. College athletes also seek to transfer institutions for reasons having nothing to do with sports, for example, a desire to be closer to home. The Transfer Eligibility Rule dampened competition in the relevant markets by deterring college athletes from exploring better options within their sport-specific market. *Id.*

Second, the Transfer Eligibility Rule also artificially disadvantaged college athletes who choose to transfer a second time by reducing their attractiveness to potential destination institutions. *Id.*

Second-time transfer college athletes were not able to apply for a waiver of the Transfer Eligibility Rule until after they had been accepted and enrolled at their new institution. Because the waiver process was discretionary and was inconsistently applied, member institutions that accepted a second-time transfer risked that the college athlete might not be eligible to compete for an entire academic year. This eligibility risk artificially deflated the value of a second-time transfer, creating an additional impediment in the market for college athlete labor. *Id.*

Third, the Transfer Eligibility Rule harmed college athletes transferring a second time by denying them the opportunity to compete in NCAA Division I athletic events for an entire academic year after transferring to a new institution. *Id.* at *6. NCAA Division I competition is the pinnacle of college athletics in the United States. Competing at this high level of athletics comes with immeasurable opportunities for personal, professional, and economic growth. For athletes seeking to continue competing professionally after college, NCAA Division I competition provides a unique platform to showcase athletic skills in front of national audiences and professional scouts. The Transfer Eligibility Rule unjustifiably denied these benefits to affected college athletes for an entire academic year. *Id.*

F. The Transfer Eligibility Rule Lacks Procompetitive Justifications

In its opposition to Plaintiffs' motion for a temporary restraining order, NCAA argued that the Transfer Eligibility Rule is procompetitive, as it "aim[s] to promote academic success by minimizing the significant potential disruption from multiple transfers, promoting the benefits of team continuity and predictability, and protecting the viability of collegiate sports by preserving some level of competitive balance between programs and some level of continuity in the makeup of teams." ECF No. 32 at 9–10.

Ruling on Plaintiffs' motion for a temporary restraining order, the Court found that these purportedly procompetitive justifications were "uncompelling" and "pretextual." *Ohio v. NCAA*, 2023 WL 9103711, at *7. The Court was unpersuaded by the NCAA's argument that the Rule promotes academic success, noting that the Rule only bars competition, not participation in practices or other team activities. Thus, second-time transfers (who as a practical matter must train and attend practice to remain viable members of their teams) are likely to spend just as much time away from their studies as

their teammates, save for a few hours of actual competition on gameday. *Id.* With respect to the NCAA's argument that the Transfer Eligibility Rule promotes team stability, the Court found that the NCAA Bylaws are silent as to the mid-season firing of coaches and contemplate first-time transfers. Accordingly, "the NCAA's stability argument [is] without merit given that there are currently no restrictions on first time transfers or coaches leaving," two circumstances that could also affect team stability. *Id.*

G. Less Restrictive Alternatives to the Transfer Eligibility Rule

To the extent the goals of the Transfer Eligibility Rule were to promote the academic well-being of college athletes and to prevent college sports from becoming a free agent market like professional sports leagues, the NCAA's other rules already promote these ends. Am. Compl. ¶ 82; *Ohio v. NCAA*, 2023 WL 9103711, at *8. For example, NCAA Bylaws already require college athletes to maintain progress toward degrees to be eligible to compete in NCAA events. NCAA Bylaw 14.4.1 requires college athletes to "maintain progress toward a baccalaureate or equivalent degree at that institution" to be eligible for intercollegiate competition at their college or university. Am. Compl. Ex. A at 150–51. In addition, NCAA Bylaw 20.2.4.13 requires member institutions to publish their progress-toward-degree requirements for college athletes, thus making these requirements available to college athletes at each institution. *Id.* at 367. Other NCAA Bylaws require minimum credit hour and grade point averages for college athletes to be eligible for competition. *Id.* at 151, 154. Additionally, NCAA Bylaws already prohibit in-season transfers within the same sport, ensuring that college athletics do not morph into a professional free agent system. Am. Compl. ¶¶ 84–86. In enjoining the Transfer Eligibility Rule, the Court found that these bylaws related to academic progress and in-season transfers accomplished NCAA's goals "without the unjustified restrictions imposed by the Transfer Eligibility Rule." *Ohio v. NCAA*, 2023 WL 9103711, at *8.

III. Explanation of the Proposed Final Judgment

The relief required by the proposed Final Judgment addresses the loss of competition alleged in the Amended Complaint. Paragraph 22 permanently enjoins the NCAA from enforcing the Transfer Eligibility Rule or any substantially similar rule requiring a

college athlete to maintain a period of residence or refrain from competition because of a transfer between NCAA member institutions. Paragraph 22 of the proposed Final Judgment also prohibits the NCAA from enforcing the Rule of Restitution on any member institution or college athlete related to a college athlete's participation in intercollegiate competition following a transfer in reliance on this Court's orders.

Paragraph 23 of the proposed Final Judgment requires the NCAA to issue an additional year of eligibility to any qualifying college athlete who was previously deemed ineligible to participate because of the Transfer Eligibility Rule for a season or any portion of a season during or since the 2019–20 academic year. Those college athletes will have no fewer than six years to complete their four seasons of intercollegiate competition and thus will not be disadvantaged from having sat out a year because of the Transfer Eligibility Rule.

The proposed Final Judgment also contains provisions designed to promote compliance with and make enforcement of the Final Judgment as effective as possible. Paragraph 30 provides that the United States retains and reserves all rights to enforce the Final Judgment, including the right to seek an order of contempt from the Court. Under the terms of this paragraph, the NCAA agrees that in any civil contempt action, any motion to show cause, or any similar action brought by the United States regarding an alleged violation of the Final Judgment, the United States may establish the violation and the appropriateness of any remedy by a preponderance of the evidence and that the NCAA has waived any argument that a different standard of proof should apply. This provision aligns the standard for compliance with the Final Judgment with the standard of proof that applies to the underlying offense that the Final Judgment addresses.

Paragraph 30 provides additional clarification regarding the interpretation of the provisions of the proposed Final Judgment. The proposed Final Judgment is intended to remedy the loss of competition that the United States alleges would otherwise result from the continued application of the Transfer Eligibility Rule. The NCAA agrees that it will abide by the proposed Final Judgment and that it may be held in contempt of the Court for failing to comply with any provision of the proposed Final Judgment that is stated specifically and in reasonable detail, as interpreted in light of this procompetitive purpose.

Paragraph 31 provides that if the Court finds in an enforcement proceeding that the NCAA has violated the Final Judgment, the United States may apply to the Court for appropriate relief, including contempt remedies and any additional relief to ensure the NCAA complies with the terms of the Final Judgment. In addition, to compensate American taxpayers for any costs associated with investigating and enforcing violations of the Final Judgment, Paragraph 31 provides that, in any successful effort by the United States to enforce the Final Judgment against the NCAA, whether litigated or resolved before litigation, the NCAA must reimburse the United States for attorneys' fees, experts' fees, and other costs incurred in connection with that effort to enforce this Final Judgment, including the investigation of the potential violation.

Under the proposed Final Judgment, the United States may file an action at any time against NCAA for other Bylaws or claims not made in this action. Paragraph 23 states that only the United States' claims with respect to the Transfer Eligibility Rule as applied to Division I college athletes is resolved pursuant to the proposed Final Judgment, and that the proposed Final Judgment specifically does not apply to any Bylaws of NCAA Division II or NCAA Division III nor does it resolve any antitrust claims regarding those rules. The proposed Final Judgment applies only to the Transfer Eligibility Rule as applied to Division I college athletes and does not mean that the United States condones any other Bylaws of NCAA Division I or any of the Bylaws of NCAA Division II or NCAA Division III.

IV. Remedies Available to Potential Private Plaintiffs

Section 4 of the Clayton Act, 15 U.S.C. 15, provides that any person who has been injured as a result of conduct prohibited by the antitrust laws may bring suit in federal court to recover three times the damages the person has suffered, as well as costs and reasonable attorneys' fees. Entry of the proposed Final Judgment neither impairs nor assists the bringing of any private antitrust damage action. Under the provisions of section 5(a) of the Clayton Act, 15 U.S.C. 16(a), the proposed Final Judgment has no prima facie effect in any subsequent private lawsuit that may be brought against Defendants.

V. Procedures Available for Modification of the Proposed Final Judgment

The United States and the NCAA have stipulated that the proposed Final Judgment may be entered by the Court after compliance with the provisions of the APPA, provided that the United States has not withdrawn its consent. The APPA conditions entry upon the Court's determination that the proposed Final Judgment is in the public interest.

The APPA provides a period of at least 60 days preceding the effective date of the proposed Final Judgment within which any person may submit to the United States written comments regarding the proposed Final Judgment. Any person who wishes to comment should do so within 60 days of the date of publication of this Competitive Impact Statement in the **Federal Register**, or within 60 days of the first date of publication in a newspaper of the summary of this Competitive Impact Statement, whichever is later. All comments received during this period will be considered by the U.S. Department of Justice, which remains free to withdraw its consent to the proposed Final Judgment at any time before the Court's entry of the Final Judgment. The comments and the response of the United States will be filed with the Court. In addition, the comments and the United States' responses will be published in the **Federal Register** unless the Court agrees that the United States instead may publish them on the U.S. Department of Justice, Antitrust Division's internet website.

Written comments should be submitted in English to: Yvette Tarlov, Chief, Media, Entertainment, and Communications Section, Antitrust Division, United States Department of Justice, 450 Fifth St. NW, Suite 7000, Washington, DC 20530, yvette.tarlov@usdoj.gov.

The proposed Final Judgment provides that the Court retains jurisdiction over this action, and the parties may apply to the Court for any order necessary or appropriate for the modification, interpretation, or enforcement of the Final Judgment.

VI. Alternatives to the Proposed Final Judgment

As an alternative to the proposed Final Judgment, the United States considered continuing the litigation and seeking a full trial on the merits against Defendant. The United States is satisfied, however, that the relief required by the proposed Final Judgment is likely to ensure competition

in the relevant markets by remedying the anticompetitive effects alleged in the Amended Complaint. Thus, the proposed Final Judgment is likely to achieve all or substantially all the relief the United States would have obtained through litigation but avoids the time, expense, and uncertainty of a full trial on the merits.

VII. Standard of Review Under the APPA for the Proposed Final Judgment

Under the Clayton Act and APPA, proposed Final Judgments, or “consent decrees,” in antitrust cases brought by the United States are subject to a 60-day comment period, after which the Court shall determine whether entry of the proposed Final Judgment “is in the public interest.” 15 U.S.C. 16(e)(1). In making that determination, the Court, in accordance with the statute as amended in 2004, is required to consider:

(A) the competitive impact of such judgment, including termination of alleged violations, provisions for enforcement and modification, duration of relief sought, anticipated effects of alternative remedies actually considered, whether its terms are ambiguous, and any other competitive considerations bearing upon the adequacy of such judgment that the court deems necessary to a determination of whether the consent judgment is in the public interest; and

(B) the impact of entry of such judgment upon competition in the relevant market or markets, upon the public generally and individuals alleging specific injury from the violations set forth in the complaint including consideration of the public benefit, if any, to be derived from a determination of the issues at trial.

15 U.S.C. 16(e)(1)(A) & (B). In considering these statutory factors, the Court’s inquiry is necessarily a limited one as the government is entitled to “broad discretion to settle with the defendant within the reaches of the public interest.” *United States v. Microsoft Corp.*, 56 F.3d 1448, 1461 (D.C. Cir. 1995); *United States v. U.S. Airways Grp., Inc.*, 38 F. Supp. 3d 69, 75 (D.D.C. 2014) (explaining that the “court’s inquiry is limited” in Tunney Act settlements); *United States v. InBev N.V./S.A.*, No. 08–1965 (JR), 2009 U.S. Dist. LEXIS 84787, at *3 (D.D.C. Aug. 11, 2009) (noting that a court’s review of a proposed Final Judgment is limited and only inquires “into whether the government’s determination that the proposed remedies will cure the antitrust violations alleged in the complaint was reasonable, and whether the mechanisms to enforce the final judgment are clear and manageable”).

As the U.S. Court of Appeals for the District of Columbia Circuit has held, under the APPA a court considers,

among other things, the relationship between the remedy secured and the specific allegations in the government’s Amended Complaint, whether the proposed Final Judgment is sufficiently clear, whether its enforcement mechanisms are sufficient, and whether it may positively harm third parties. *See Microsoft*, 56 F.3d at 1458–62. With respect to the adequacy of the relief secured by the proposed Final Judgment, a court may not “make de novo determination of facts and issues.” *United States v. W. Elec. Co.*, 993 F.2d 1572, 1577 (D.C. Cir. 1993) (quotation marks omitted); *see also Microsoft*, 56 F.3d at 1460–62; *United States v. Alcoa, Inc.*, 152 F. Supp. 2d 37, 40 (D.D.C. 2001); *United States v. Enova Corp.*, 107 F. Supp. 2d 10, 16 (D.D.C. 2000); *InBev*, 2009 U.S. Dist. LEXIS 84787, at *3. Instead, “[t]he balancing of competing social and political interests affected by a proposed antitrust decree must be left, in the first instance, to the discretion of the Attorney General.” *W. Elec. Co.*, 993 F.2d at 1577 (quotation marks omitted). “The court should also bear in mind the flexibility of the public interest inquiry: the court’s function is not to determine whether the resulting array of rights and liabilities is the one that will best serve society, but only to confirm that the resulting settlement is within the reaches of the public interest.” *Microsoft*, 56 F.3d at 1460 (quotation marks omitted); *see also United States v. Deutsche Telekom AG*, No. 19–2232 (TJK), 2020 WL 1873555, at *7 (D.D.C. Apr. 14, 2020). More demanding requirements would “have enormous practical consequences for the government’s ability to negotiate future settlements,” contrary to congressional intent. *Microsoft*, 56 F.3d at 1456. “The Tunney Act was not intended to create a disincentive to the use of the consent decree.” *Id.*

The United States’ predictions about the efficacy of the remedy are to be afforded deference by the Court. *See, e.g., Microsoft*, 56 F.3d at 1461 (recognizing courts should give “due respect to the Justice Department’s . . . view of the nature of its case”); *United States v. Iron Mountain, Inc.*, 217 F. Supp. 3d 146, 152–53 (D.D.C. 2016) (“In evaluating objections to settlement agreements under the Tunney Act, a court must be mindful that [t]he government need not prove that the settlements will perfectly remedy the alleged antitrust harms[;] it need only provide a factual basis for concluding that the settlements are reasonably adequate remedies for the alleged harms.” (internal citations omitted)); *United States v. Republic Servs., Inc.*,

723 F. Supp. 2d 157, 160 (D.D.C. 2010) (noting “the deferential review to which the government’s proposed remedy is accorded”); *United States v. Archer-Daniels-Midland Co.*, 272 F. Supp. 2d 1, 6 (D.D.C. 2003) (“A district court must accord due respect to the government’s prediction as to the effect of proposed remedies, its perception of the market structure, and its view of the nature of the case.”). The ultimate question is whether “the remedies [obtained by the Final Judgment are] so inconsonant with the allegations charged as to fall outside of the ‘reaches of the public interest.’” *Microsoft*, 56 F.3d at 1461 (quoting *W. Elec. Co.*, 900 F.2d at 309).

Moreover, the Court’s role under the APPA is limited to reviewing the remedy in relationship to the violations that the United States has alleged in its Amended Complaint, and does not authorize the Court to “construct [its] own hypothetical case and then evaluate the decree against that case.” *Microsoft*, 56 F.3d at 1459; *see also U.S. Airways*, 38 F. Supp. 3d at 75 (noting that the court must simply determine whether there is a factual foundation for the government’s decisions such that its conclusions regarding the proposed settlements are reasonable); *InBev*, 2009 U.S. Dist. LEXIS 84787, at *20 (“[T]he ‘public interest’ is not to be measured by comparing the violations alleged in the complaint against those the court believes could have, or even should have, been alleged”). Because the “court’s authority to review the decree depends entirely on the government’s exercising its prosecutorial discretion by bringing a case in the first place,” it follows that “the court is only authorized to review the decree itself,” and not to “effectively redraft the complaint” to inquire into other matters that the United States did not pursue. *Microsoft*, 56 F.3d at 1459–60.

In its 2004 amendments to the APPA, Congress made clear its intent to preserve the practical benefits of using judgments proposed by the United States in antitrust enforcement, Public Law 108–237 § 221, and added the unambiguous instruction that “[n]othing in this section shall be construed to require the court to conduct an evidentiary hearing or to require the court to permit anyone to intervene.” 15 U.S.C. 16(e)(2); *see also U.S. Airways*, 38 F. Supp. 3d at 76 (indicating that a court is not required to hold an evidentiary hearing or to permit intervenors as part of its review under the Tunney Act). This language explicitly wrote into the statute what Congress intended when it first enacted the Tunney Act in 1974. As Senator Tunney explained: “[t]he court is

nowhere compelled to go to trial or to engage in extended proceedings which might have the effect of vitiating the benefits of prompt and less costly settlement through the consent decree process.” 119 Cong. Rec. 24,598 (1973) (statement of Sen. Tunney). “A court can make its public interest determination based on the competitive impact statement and response to public comments alone.” *U.S. Airways*, 38 F. Supp. 3d at 76 (citing *Enova Corp.*, 107 F. Supp. 2d at 17).

VIII. Determinative Documents

There are no determinative materials or documents within the meaning of the APPA that were considered by the United States in formulating the proposed Final Judgment.

Dated: May 30, 2024

Respectfully,

Maximillian F. Nogay
Assistant United States Attorney

United States Attorney's Office, Northern District of West Virginia, P.O. Box 591, 1125 Chapline Street, Suite 3000, Wheeling, WV 26003, Tel: 304-234-0100, Fax: 304-234-0110, Email: max.nogay@usdoj.gov.

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Trial Attorney

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* *pro hac vice*

Attorneys for Plaintiff United States of America

[FR Doc. 2024-12720 Filed 6-10-24; 8:45 am]

BILLING CODE 4410-11-P

DEPARTMENT OF JUSTICE

[OMB 1140-0087]

Agency Information Collection Activities; Proposed eCollection Activities; Requested; Revision of a Previously Approved Collection eForm Access Request/User Registration

AGENCY: Bureau of Alcohol, Tobacco, Firearms and Explosives, Department of Justice.

ACTION: 60-Day notice.

SUMMARY: The Department of Justice (DOJ), The Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF), will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995.

DATES: Comments are encouraged and will be accepted for 60 days until August 12, 2024.

FOR FURTHER INFORMATION CONTACT: If you have additional comments especially on the estimated public burden or associated response time, suggestions, or need a copy of the proposed information collection instrument with instructions or additional information, contact: Victoria Kenney, FEIB/FESD, either by mail at 244 Needy Road, Martinsburg, WV 25405, by email at Victoria.Kenney@atf.gov, or telephone at 304-616-3376.

SUPPLEMENTARY INFORMATION: Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Bureau of Justice Statistics, 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;
- Evaluate whether and if so how the quality, utility, and clarity of the information to be collected can be enhanced; 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.

Abstract: The information on this form allows users to obtain access to the eForms system to submit various forms to ATF and allows ATF to authenticate those users. Information Collection (IC) OMB 1140-0087—eForm Access Request/User Registration is being revised to include updated screenshots that reflect the new systems appearance and layout. New system updates have led to the prior screenshots being outdated.

Overview of This Information Collection

1. *Type of Information Collection:* Revision of a previously approved collection.

2. *The Title of the Form/Collection:* eForm Access Request/User Registration.

3. *The agency form number, if any, and the applicable component of the Department sponsoring the collection:* Form number: None.

Component: Bureau of Alcohol, Tobacco, Firearms and Explosives, U.S. Department of Justice.

4. *Affected public who will be asked or required to respond, as well as the obligation to respond:* Affected Public: Private Sector-for or not for profit institutions.

The obligation to respond is voluntary.

5. *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* An estimated 390,000 respondents will complete this registration form annually, and it will take each respondent approximately 2.24 minutes to complete their responses.

6. *An estimate of the total annual burden (in hours) associated with the collection:* The estimated annual public burden associated with this collection is 2837 hours, which is equal to 390,000 (total respondents) * 1 (# of response per respondent) * .00727436 (2.24 minutes).

7. *An estimate of the total annual cost burden associated with the collection, if applicable:* \$0.

TOTAL BURDEN HOURS

Activity	Number of respondents	Frequency	Total annual responses	Time per response	Total annual burden (hours)
eForm Access Request/User Registration	390,000	1/annually	390,000	2.24 minutes ..	2837
Unduplicated Totals.					

If additional information is required contact: Darwin Arceo, Department Clearance Officer, United States Department of Justice, Justice Management Division, Policy and Planning Staff, Two Constitution Square, 145 N Street NE, 4W-218, Washington, DC.

Dated: May 6, 2024.

Darwin Arceo,

Department Clearance Officer for PRA, U.S. Department of Justice.

[FR Doc. 2024-12762 Filed 6-10-24; 8:45 am]

BILLING CODE 4410-FY-P

DEPARTMENT OF JUSTICE

[OMB Number 1105-0092]

Agency Information Collection Activities; Proposed eCollection eComments Requested; Reinstatement Without Change September 11th Victim Compensation Fund ("VCF") Claim Form

AGENCY: Department of Justice.

ACTION: 30-Day notice.

SUMMARY: The September 11th Victim Compensation Fund, Department of Justice (DOJ), will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. The proposed information collection was previously published in the **Federal Register** on January 29, 2024, allowing a 60-day comment period.

DATES: Comments are encouraged and will be accepted for 30 days until July 11, 2024.

FOR FURTHER INFORMATION CONTACT: If you have comments especially on the estimated public burden or associated response time, suggestions, or need a copy of the proposed information collection instrument with instructions or additional information, please contact: Kimberly Brown, Director of Operations, September 11th Victim Compensation Fund, 1100 L Street NW, Washington, DC 20531 (855) 885-1555 or (202) 507-6453; email: Kimberly.C.Brown@usdoj.gov.

SUPPLEMENTARY INFORMATION: Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should

address one or more of the following four points:

- 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/or
- 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.

Written comments and recommendations for this information collection should be submitted within 30 days of the publication of this notice on the following website 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 and entering either the title of the information collection or the OMB Control Number 1105-0092. This information collection request may be viewed at www.reginfo.gov. Follow the instructions to view Department of Justice, information collections currently under review by OMB.

DOJ 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 DOJ notes that information collection requirements submitted to the OMB for existing ICRs receive a month-to-month extension while they undergo review.

Overview of This Information Collection

1. *Type of Information Collection:* Reinstatement of a previously approved collection.
2. *Title of the Form/Collection:* VCF Claim Form.
3. Agency form number, if any, and the applicable component of the Department of Justice sponsoring the collection: N/A. Civil Division

4. Affected public who will be asked or required to respond, as well as a brief abstract: Individuals or households.

The September 11th Victim Compensation Fund of 2001 ("VCF" or "Fund") provides compensation to any individual (or beneficiary of a deceased individual) who was physically injured or killed as a result of the terrorist-related aircraft crashes of September 11, 2001. The information collected from the VCF Claim Form will be used to determine whether claimants will be eligible for compensation from the Fund, and if so, the amount of compensation they will be awarded. The Form consists primarily of two main sections: Eligibility and Compensation.

The Eligibility section seeks the information required by the Zadroga Act to determine whether a claimant is eligible for the Fund, including information related to: participation in lawsuits related to September 11, 2001; presence at a 9/11 crash site between September 11, 2001 and May 30, 2002; and physical harm suffered as a result of the air crashes and/or debris removal.

The Compensation section seeks the information required by the Zadroga Act to determine the amount of compensation for which the claimant is eligible. Specifically, the section seeks information regarding the out-of-pocket losses (including medical expenses) incurred by the claimant that are attributable to the 9/11 air crashes or debris removal; the claimant's loss of earnings or replacement services that are attributable to the 9/11 air crashes or debris removal; and any collateral source payments (such as insurance payments) that the claimant received as a result of the terrorist-related aircraft crashes of September 11, 2001 or debris removal efforts.

5. *Obligation to Respond:* Required to obtain or retain a benefit.

6. *Total Estimated Number of Respondents:* 21,000 (total estimate for the time period from June 2024 through June 2027).

7. *Estimated Time per Respondent:* 8 hours.

8. *Frequency:* One time only.

9. *Total Estimated Annual Time Burden:* The estimated annual burden associated with this collection is 168,000 hours.

10. *Total Estimated Annual Other Costs Burden:*

TOTAL BURDEN HOURS

Activity	Number of respondents	Frequency	Total annual responses	Time per response (hours)	Total annual burden (hours)
September 11th Victim Compensation Fund Claim Form.	21,000	1/annually	21,000	8	168,000

If additional information is required, contact: Darwin Arceo, Department Clearance Officer, Policy and Planning Staff, Justice Management Division, United States Department of Justice, Two Constitution Square, 145 N Street NE, 4W-218, Washington, DC 20530.

Darwin Arceo,

Department Clearance Officer for PRA, U.S. Department of Justice.

[FR Doc. 2024-12279 Filed 6-10-24; 8:45 am]

BILLING CODE 4410-12-P

EMPLOYEE BENEFITS SECURITY ADMINISTRATION

[Exemption Application No. D-12098]

Proposed Exemption for Certain Prohibited Transaction Restrictions Involving UBS AG (UBS) Located in Zurich, Switzerland

AGENCY: Employee Benefits Security Administration, Department of Labor.

ACTION: Notice of proposed exemption.

SUMMARY: This document provides notice of the pendency before the Department of Labor (the Department) of a proposed individual exemption from certain of the prohibited transaction restrictions of the Employee Retirement Income Security Act of 1974 (ERISA or the Act) and/or the Internal Revenue Code of 1986 (the Code). The Department previously issued an individual prohibited transaction exemption (PTE) 2023-14 that allowed certain asset managers related to UBS (the Applicant) and Credit Suisse Group AG (CSAG) to continue to rely on the exemptive relief provided by Prohibited Transaction Exemption 84-14 for one year following UBS' acquisition of CSAG. This proposed exemption would allow current and future asset managers under the UBS corporate umbrella to continue to rely on PTE 84-14 from June 12, 2024, to June 11, 2029 if certain conditions were met, notwithstanding the five judgments of conviction involving entities within the UBS and CSAG corporate umbrellas that are described below.

DATES: If granted, this proposed exemption will be in effect for the period beginning on June 12, 2024, and

ending on June 11, 2029, and may also provide retrospective relief for part or all of the period covered by the preceding exemption, PTE 2023-14, which permitted the UBS QPAMs to rely on PTE 84-14 and extended from June 12, 2023, through June 11, 2024.

Comments due: Written comments and requests for a public hearing on the proposed exemption should be submitted to the Department by July 15, 2024.

ADDRESSES: All written comments and requests for a hearing should be sent to the Employee Benefits Security Administration (EBSA), Office of Exemption Determinations, Attention: Application No. D-12098, via email to e-OED@dol.gov or online through <http://www.regulations.gov>. Any such comments or requests should be sent by the end of the scheduled comment period. The application for exemption and the comments received will be available for public inspection in the Public Disclosure Room of the Employee Benefits Security Administration, U.S. Department of Labor, Room N-1515, 200 Constitution Avenue NW, Washington, DC 20210 ((202) 693-8673). See **SUPPLEMENTARY INFORMATION** below for additional information regarding comments.

FOR FURTHER INFORMATION CONTACT: Nicholas Schroth of the Department at (202) 693-8571. (This is not a toll-free number.)

SUPPLEMENTARY INFORMATION:

Comments

1. Persons are encouraged to submit all comments electronically and not to follow with paper copies. Comments should state the nature of the person's interest in the proposed exemption and the manner in which the person would be adversely affected by the exemption, if granted. Any person who may be adversely affected by an exemption can request that the Department holds a hearing on the exemption. A request for a hearing must state: (1) the name, address, telephone number, and email address of the person making the request; (2) the nature of the person's interest in the exemption and the manner in which the person would be adversely affected by the exemption; and (3) a statement of the issues to be

addressed and a general description of the evidence to be presented at the hearing. The Department will grant a request for a hearing made in accordance with the requirements above where a hearing is necessary to fully explore material factual issues identified by the person requesting the hearing. A notice of such hearing shall be published by the Department in the **Federal Register**. The Department may decline to hold a hearing if: (1) the request for the hearing does not meet the requirements above; (2) the only issues identified for exploration at the hearing are matters of law; or (3) the factual issues identified can be fully explored through the submission of evidence in written (including electronic) form.

2. **Warning:** All comments received will be included in the public record without change and may be made available online at <http://www.regulations.gov>, including any personal information provided, unless the comment includes information claimed to be confidential or other information whose disclosure is restricted by statute. If you submit a comment, EBSA recommends that you include your name and other contact information in the body of your comment, but DO NOT submit information that you consider to be confidential, or otherwise protected (such as a Social Security number or an unlisted phone number) or confidential business information that you do not want publicly disclosed. However, if EBSA cannot read your comment due to technical difficulties and cannot contact you for clarification, EBSA might not be able to consider your comment. Additionally, the <http://www.regulations.gov> website is an "anonymous access" system, which means EBSA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email directly to EBSA without going through <http://www.regulations.gov>, your email address will be automatically captured and included as part of the comment that is placed in the public record and made available on the internet.

Background

3. Upon the expiration of the one-year period set forth in PTE 2023–14 (June 12, 2024), the exemption no longer will provide the Applicant with relief from ERISA’s prohibited transaction provisions. This proposed exemption would allow current and future asset managers under the UBS corporate umbrella to continue to rely on PTE 84–14 from June 12, 2024, to June 11, 2029, if the conditions specified herein are satisfied. As described below, the Department is proposing the exemption to protect affected plans from the harms that the Applicant has represented would occur if the UBS QPAMs are no longer allowed to engage in the transactions permitted by PTE 84–14. The Department also seeks comments on whether the requested exemption, if granted, should include retrospective relief covering transactions that would have been permitted under the QPAMs’ previous exemption, (PTE 2023–14), but for their failure to comply timely with the audit requirements of that exemption.

4. The current UBS-affiliated asset managers that rely on PTE 84–14 are UBS Asset Management (Americas) LLC, and UBS Hedge Fund Solutions LLC (together with any future entity within the Asset Management or the Global Wealth Management Americas U.S. divisions of UBS that qualifies as a “qualified professional asset manager” as defined in Section VI(a) of PTE 84–14, (hereafter referred to as the Affiliated QPAMs)). In addition, UBS holds or may in the future hold a greater than five (5) percent interest in a number of smaller asset managers that are not considered to be “affiliates” of UBS and also may qualify as a “qualified professional asset manager” as defined in Section VI(a) of PTE 84–14 (the Related QPAMs). The Affiliated QPAMs and Related QPAMs are collectively referred to herein as the “UBS QPAMs.” This proposed exemption, if granted, would enable UBS QPAMs to continue to rely on PTE 84–14 for a five-year period ending on June 11, 2029, if the conditions of this exemption are met, notwithstanding four criminal convictions of entities within the UBS corporate family that occurred within the last 10 years.¹ The proposed exemption would provide the Applicant with continued relief under PTE 84–14 which, in turn, would provide relief from restrictions set forth

in ERISA sections 406 and 407.² In addition, the Applicant is requesting that the Department structure the exemption in such a way that it avoids the loss of relief under the terms of PTE 2023–14 as a result of its failure to timely comply with the audit requirements set forth in that exemption. No relief from a violation of any other law would be provided by this exemption, including any criminal conviction described herein.

Benefits of the Proposed Exemption

5. The Department is proposing relief based on the Applicant’s representation that significant harm to the Applicant’s Covered Plan clients would be prevented if the Department grants an exemption. The Department’s objective in proposing this exemption is to protect Covered Plans from the harms and costs that could be imposed on them if the UBS QPAMs no longer could rely on the relief provided in PTE 84–14. Furthermore, the terms of this exemption are intended to promote the UBS QPAMs’ adherence to basic fiduciary standards under Title I of ERISA and the Code and reinforce their obligation to act with a high degree of integrity on behalf of their Covered Plan clients.

6. The Department notes that this individual exemption would solely provide relief from the limitations of PTE 84–14 Section I(g) with respect to the four criminal convictions of entities within the UBS corporate family that are described below. The conditions of this exemption explicitly require the UBS QPAMs to adhere to every other condition for relief specified in PTE 84–14, as amended, including the robust disqualification provisions found in Section I(g). If any condition of PTE 84–14, as amended, is violated by a UBS Affiliated QPAM, that QPAM would fail to comply with the requirements of the exemption.

Summary of Facts and Representations³

7. UBS is a Swiss-based global financial services company organized

under the laws of Switzerland. UBS Asset Management (Americas) LLC and UBS Hedge Fund Solutions LLC are entities under the UBS corporate umbrella that currently operate as QPAMs and manage the assets of Covered Plans⁴ on a discretionary basis in reliance on PTE 84–14.⁵ On June 12, 2023, UBS acquired CSAG, another Swiss-based global financial services firm. This acquisition brought Credit Suisse Asset Management, LLC, a subsidiary of CSAG, under the UBS corporate umbrella. The Applicant represents that, on May 1, 2024, Credit Suisse Asset Management, LLC (an entity that previously constituted an Affiliated QPAM) was merged into UBS Asset Management (Americas) LLC, with UBS Asset Management (Americas) LLC being the surviving entity. The only current Affiliated QPAMs are UBS Asset Management (Americas) LLC and UBS Hedge Fund Solutions LLC.

Relevant ERISA Provisions and PTE 84–14

8. The rules set forth in ERISA section 406 and Code section 4975(c)(1) proscribe certain “prohibited transactions” between plans and related parties with respect to those plans. Under ERISA section 3(14), such parties are known as “parties in interest” with respect to a plan, and include, among others, the plan fiduciary, a sponsoring employer of the plan, a union whose members are covered by the plan, service providers with respect to the plan, and certain of their affiliates.⁶

the exemption will cease to apply as of the date of the change.

⁴ The term “Covered Plan” means a plan subject to Part IV of Title I of ERISA (an ERISA-covered plan) or a plan subject to Code section 4975 (an IRA), in each case, with respect to which an Affiliated QPAM relies on PTE 84–14 or with respect to which an Affiliated QPAM (or any UBS affiliate) has expressly represented that the manager qualifies as a QPAM or relies on PTE 84–14. A Covered Plan does not include an ERISA-covered plan or IRA to the extent the Affiliated QPAM has expressly disclaimed reliance on QPAM status or PTE 84–14 in entering into a contract, arrangement, or agreement with the ERISA-covered plan or IRA. Notwithstanding the above, an Affiliated QPAM may disclaim reliance on QPAM status or PTE 84–14 in a written modification of a contract, arrangement, or agreement with an ERISA-covered plan or IRA, where: the modification is made in a bilateral document signed by the client; the client’s attention is specifically directed toward the disclaimer; and the client is advised in writing that, with respect to any transaction involving the client’s assets, the Affiliated QPAM will not represent that it is a QPAM, and will not rely on the relief described in PTE 84–14.

⁵ UBS represents that UBS O’Connor LLC and UBS Realty Investors LLC are entities under the UBS corporate umbrella that currently offer investment products which are assessable by ERISA-covered plans, but do not currently rely on Class PTE 84–14 when managing those products.

⁶ Under the Code, such parties, or similar parties, are referred to as “disqualified persons.”

¹ Relief in this exemption is not provided for one of the criminal convictions covered by PTE 2023–14, because that conviction occurred outside the 10-year ineligibility period under PTE 84–14 Section I(g).

² Unless otherwise specified, references to specific provisions of Title I of ERISA also refers to the corresponding provisions of Code section 4975.

³ The Summary of Facts and Representations is based on UBS representations and does not reflect factual findings or opinions of the Department unless indicated otherwise. The Department notes that availability of this exemption is subject to the express condition that the material facts and representations made by UBS are true, complete, and accurately describe all material terms of the transaction(s) covered by the exemption. If there is any material change in a transaction covered by the exemption, or in a material fact or representation that is part of the record attributable to D–12098,

9. The prohibited transaction provisions under ERISA section 406(a) and Code section 4975(c)(1) prohibit, in relevant part, sales, leases, loans or the provision of services between a party in interest and a plan (or an entity whose assets are deemed to constitute the assets of a plan), as well as the use of plan assets by or for the benefit of a party in interest or a transfer of plan assets to a party in interest.⁷ Under ERISA section 408(a) and Code section 4975(c)(2), the Department has the authority to grant exemptions from such “prohibited transactions” in accordance with its exemption procedures if the Department finds that an exemption is (1) administratively feasible for the Department; (2) in the interests of the plan and of its participants and beneficiaries; and (3) protective of the rights of participants and beneficiaries.⁸ PTE 84–14 reflects the Department’s conclusion that it could provide broad relief from the prohibited transaction provisions of ERISA section 406(a) and Code section 4975(c)(1) only if the commitments and the investments of plan assets and the negotiations leading thereto are the sole responsibility of an independent discretionary manager the meets the exemption’s conditions.

10. PTE 84–14 Section I(g) prevents an entity that may otherwise meet the QPAM definition from utilizing the exemptive relief provided by PTE 84–14 for itself and its client plans, if that entity, an “affiliate” thereof,⁹ or any direct or indirect five percent or more owner in the QPAM has within 10 years immediately preceding the transaction, been: (1) either convicted or released from imprisonment, whichever is later, as a result of criminal activity described in Section I(g); or (2) engaged in prohibited misconduct as described in

that section (in both cases subject to the Ineligibility Date described in Section I(h)).¹⁰

11. The Department’s inclusion of Section I(g) in PTE 84–14 is, in part, based on an expectation that QPAMs will maintain a high standard of integrity. This expectation extends not only to the QPAM itself but also to those who may be in a position to influence the policies of the QPAM.

Five Relevant Convictions

The 2017 UBS Conviction

12. In 2013, UBS Securities Japan Co. Ltd. (UBS Securities Japan) pled guilty to a crime arising out of its fraudulent submission of Yen London Interbank Offer Rate (Yen LIBOR) rates between 2006 and 2009, and its participation in a scheme to defraud counterparties to interest rate derivatives trades executed on its behalf, by secretly manipulating certain benchmark interest rates to which the profitability of those trades was tied (the 2013 UBS Conviction).¹¹

13. In connection with misconduct related to the 2013 UBS Conviction, UBS and the DOJ entered into a Non-Prosecution Agreement (the LIBOR NPA) wherein the DOJ agreed not to criminally prosecute UBS for any crimes related to UBS’s misconduct involving its submission of Yen LIBOR rates and other benchmark rates between 2001 and 2010 (LIBOR Manipulation). As a condition for the DOJ’s agreement not to prosecute UBS for the LIBOR Manipulation, UBS was required, among other things, to avoid engaging in additional criminal activity for two years from the date of the NPA.

14. Separately from the LIBOR Manipulation and after entering into the NPA, UBS was also revealed to have participated in certain deceptive currency trading and sales practices with respect to certain foreign exchange (FX) market transactions and collusive conduct in certain FX markets (FX Misconduct). The DOJ determined that by engaging in the FX Misconduct, UBS had breached the terms of the LIBOR NPA. As a result, UBS entered a guilty plea and was convicted on January 10, 2017 of engaging in the LIBOR Manipulation that was the subject of the LIBOR NPA—specifically, UBS pled

guilty to a scheme to defraud counterparties to interest rate derivatives transactions by secretly manipulating benchmark interest rates to which the profitability of those transactions was tied. This is referred to as the “2017 UBS Conviction”.¹² PTE 84–14, Section I(g), disqualifies UBS-related QPAMs from relying on the relief set forth in PTE 84–14 for ten years, from January 10, 2017, to January 9, 2027.

The 2014 CSAG Conviction

15. On May 19, 2014, the Tax Division of the United States Department of Justice (DOJ) and the U.S. Attorney’s Office for the Eastern District of Virginia filed a one-count criminal information in the District Court for the Eastern District of Virginia charging CSAG with a conspiracy to violate Code section 7206(2) in violation of Title 18, United States Code, Section 371. According to the Statement of Facts, for decades before and through approximately 2009 CSAG operated an illegal cross-border banking business that knowingly and willfully aided and assisted thousands of U.S. clients in opening and maintaining undeclared accounts that concealed offshore assets and income from the IRS. On May 19, 2014, pursuant to a plea agreement (the Plea Agreement), CSAG entered a plea of guilty for assisting U.S. citizens in federal income tax evasion. The District Court entered a judgment of conviction against CSAG on November 21, 2014. PTE 84–14, Section I(g), disqualifies CSAG-related (and, thus, UBS-related QPAMs) from the relief set forth in PTE 84–14 for ten years, from November 21, 2014 to November 20, 2024.

The 2019 UBS France Conviction

16. In 2013, France opened an investigation into UBS, UBS France, and certain former employees of UBS France S.A. The investigation centered on the maintenance of foreign (“cross-border”) UBS bank accounts held for private citizens. Following a trial in the French First Instance Court, the French court convicted UBS and UBS France on February 20, 2019, of illegally soliciting clients from 2004 to 2012 and laundering the proceeds of tax fraud from 2004 to 2012. PTE 84–14, Section I(g), disqualifies UBS-related QPAMs from relying on the relief in PTE 84–14 for ten years, from February 20, 2019 to February 19, 2029.

¹² In PTE 2023–14, the Department erroneously referred to this conviction as the 2018 Conviction. The actual conviction occurred on January 10, 2017 (as described in the prior UBS PTE 2020–01).

⁷ The prohibited transaction provisions also include certain fiduciary prohibited transactions under ERISA section 406(b) and Code section 4975(c)(1)(E) and (F). These include transactions involving fiduciary self-dealing, fiduciary conflicts of interest, and kickbacks to fiduciaries. PTE 84–14 provides only very narrow conditional relief for transactions described in ERISA section 406(b).

⁸ 29 CFR part 2570, subpart B at 76 FR 66637, 66644, October 27, 2011, amended at 89 FR 4662, January 24, 2024.

⁹ Section VI(d) of PTE 84–14 defines the term “affiliate” for purposes of Section I(g) as “(1) Any person directly or indirectly through one or more intermediaries, Controlling, Controlled by, or under Common Control with the person; (2) Any director of, Relative of, or partner in, any such person, (3) Any corporation, partnership, trust or unincorporated enterprise of which such person is an officer, director, or a five percent or more partner or owner; and (4) Any employee or officer of the person who—(A) Is a highly compensated employee (as defined in Code section 4975(e)(2)(H) or officer (earning ten (10) percent or more of the yearly wages of such person); or (B) Has direct or indirect authority, responsibility, or control regarding the custody, management or disposition of Plan assets.”

¹⁰ The prohibited misconduct provision is effective on June 17, 2024.

¹¹ In connection with the 2013 Conviction, the UBS QPAMs received exemptive relief to continue to rely on PTE 84–14 notwithstanding such conviction. However, the disqualification period under Section I(g) of PTE 84–14 with respect to the 2013 Conviction expired on or about February 19, 2023 and therefore the UBS QPAMs no longer require an exemption to continue to rely on PTE 84–14 with respect to that conviction.

The 2022 Credit Suisse Securities (Europe) Limited (CSSEL) Conviction

17. On October 19, 2021, the DOJ, Criminal Division, Money Laundering and Asset Recovery Section and Fraud Section, and the United States Attorney's Office for the Eastern District of New York, filed a criminal information in the District Court for the Eastern District of New York charging CSSEL with one count of conspiracy to commit wire fraud in violation of 18 U.S.C. 1349. CSSEL agreed to resolve the action through a plea agreement presented to the New York District Court on October 19, 2021 (the CSSEL Plea Agreement). Under the CSSEL Plea Agreement, CSSEL agreed to enter a plea of guilty to the charge set out in the CSSEL information (the CSSEL Plea). The District Court entered a judgment of conviction against CSSEL on July 22, 2022. PTE 84–14, Section I(g), disqualifies CSAG-related QPAMs (and, thus, UBS-related QPAMs) from relying on the relief set forth in PTE 84–14 for ten years, from July 22, 2022 to July 21, 2032.

Prior Exemptions

18. The UBS entities of UBS Asset Management (Americas) Inc., UBS Realty Investors LLC, UBS Hedge Fund Solutions LLC, and UBS O'Connor LLC (the Prior UBS Applicants) and two CSAG asset management affiliates, Credit Suisse Asset Management, LLC and Credit Suisse Asset Management Limited, as well as other entities in which CSAG owned a five percent or more interest (cumulatively, the Prior Applicants), historically relied on the exemptive relief provided in PTE 84–14. To protect Covered Plans from the costs and harms that could arise if the Prior Applicants lost their ability to engage in beneficial transactions on behalf of the Covered Plans due to the convictions described above, the Department issued a number of individual exemptions. The Department's practice was to issue temporary short-term exemptions that generally lasted for a one-year period to enable the Department to conduct an in-depth evaluation of the Prior Applicants' criminal activity and compliance regimes. These short-term temporary exemptions afforded the Department time to: (i) ascertain whether exemptive relief was warranted based on a robust demonstration from Applicants of the harms that could be sustained by Covered Plan clients if the Department chose not to provide longer-term relief; (ii) develop stringent conditions designed to safeguard the interests of Covered Plan clients; and (iii) more fully develop the factual

record to determine if it supports relief. Generally, the temporary exemptions were followed by longer-term exemptions that were limited to four or five-year time periods. These longer term (but still temporary) exemptions provided the Department with a further opportunity to ascertain whether the exemptions continued to be in the interest of the Applicant's Covered Plan clients and the conditions continued to be protective of their rights and interests. In connection with Credit Suisse-related convictions, the Department issued the following exemptions: PTE 2022–01 (87 FR 1186 (Jan. 10, 2022)); PTE 2019–07 (84 FR 61928 (Nov. 14, 2019)); PTE 2015–14 (80 FR 59817 (Oct. 2, 2015)); PTE 2014–11 (79 FR 68716 (Nov. 18, 2014)). In connection with the UBS-related convictions, the Department issued: PTE 2020–01 (85 FR 8020 (Feb. 12, 2020)); PTE 2019–01 (84 FR 6163 (Feb. 26, 2019)); PTE 2017–07 (82 FR 61903 (Dec. 29, 2017)); PTE 2016–17 (81 FR 94049 (Dec. 22, 2016)); PTE 2013–09 (78 FR 56740 (Sep. 13, 2013)).

Merger of UBS and CSAG

19. PTE 2020–01 permitted the UBS asset managers to continue to rely on PTE 84–14 only if, among other things, UBS and its affiliates had not been convicted of a crime described in Section I(g) of PTE 84–14 over the prior 10 years, other than the UBS-related convictions described above. Similarly, PTE 2022–01 permitted Credit Suisse QPAMs to continue to rely on PTE 84–14 only if, among other things, such entities and their affiliates had not been convicted of a crime described in Section I(g) of PTE 84–14 other than the CSAG-related convictions described above. Following the Merger, UBS was affiliated with CSAG and CSSEL; therefore, the convictions attributable to CSAG and CSSEL resulted in a violation of PTE 2020–01. In addition, CSAG was affiliated with UBS, UBS Securities Japan, and UBS France, and was accountable for the convictions attributable to those entities in violation of PTE 2022–01.

20. In order to protect Covered Plans that could be harmed by the sudden loss of PTE 2020–01 and PTE 2022–01 due to the Merger, the Department granted PTE 2023–14 which was effective on the Merger date (June 12, 2023). PTE 2023–14 granted relief only for the one-year period following the closing of the Merger in order to afford Department sufficient time to build a record upon which it could make its findings under ERISA section 408(a) that longer-term exemptive relief was warranted and for UBS and Credit Suisse's covered plan

clients to exercise their discretion to find a different investment manager in the event they deemed it was prudent to do so in light of the numerous convictions of these entities and their affiliates.

Application for Five-Year Extension

21. On February 22, 2024, UBS applied to the Department for a five-year extension of the relief granted in PTE 2023–14 that would allow the UBS QPAMs to rely on PTE 84–14 notwithstanding the 2014 CSAG Conviction, the 2022 CSSEL Conviction, the 2017 UBS Conviction, and the 2019 UBS France Conviction. These four criminal convictions are hereinafter referred to as the "Covered Convictions."¹³ The Applicant represents that the conduct underlying the Covered Convictions occurred within business divisions that are separate from UBS QPAMs and that the UBS QPAMs are insulated from the business divisions where the wrongdoing incurred by policies, procedures, and dedicated personnel.

22. *Department's Note:* Although only the Covered Convictions would cause the UBS QPAMs to become ineligible under PTE 84–14 Section I(g), the Department also is concerned about the conduct underlying the 2013 UBS Conviction and the FX Misconduct. Therefore, the Department has conditioned relief in the proposed exemption on the Applicant's insulation of the UBS QPAMs from the conduct underlying the Covered Convictions, the FX Misconduct, and the 2013 UBS Conviction (referred to in the aggregate as the Criminal Activity). Accordingly, the Department uses the term "Misconduct Entity" in the proposed exemption to refer to any of the following: an entity subject to one of the Covered Convictions, *i.e.*, UBS, UBS France (recently merged into UBS Europe), CSAG and CSSEL; an entity that is the subject of the 2013 Conviction, *i.e.*, UBS Securities Japan; and the entity that is the subject of the FX Misconduct, *i.e.*, also UBS. Similarly, the Department uses the term "Criminal Activity" in the proposed exemption to refer to the facts underlying the Covered Convictions, the 2013 UBS Conviction, and the FX Misconduct in order to ensure the insulation of the UBS QPAMs from the past criminal behavior of entities in the UBS and Credit Suisse corporate families.

¹³ As noted above, the UBS QPAMs represent that they no longer need exemptive relief from the prohibitions of PTE 84–14 Section I(g) with respect to the 2013 UBS Conviction.

23. In its exemption application, UBS represents that every independent audit that has been performed has determined that the UBS QPAMs met the terms and conditions of each exemption. Finally, as described below, UBS represents that an exemption would prevent significant harms and costs from being imposed on the UBS QPAMs' Covered Plan clients if the UBS QPAMs no longer could rely on the relief provided in PTE 84–14.

Retroactive Relief Periods

24. Based on its review of the record, the UBS QPAMs appear to have lost their exemptive relief for the period from June 12, 2023, through June 11, 2024 (the PTE 2023–14 Period) because of their failure, during the pendency of the exemption, to comply with the audit conditions set forth in Section III(j) of PTE 2023–14, as described below.

25. In addition, UBS will not have relief for the period subsequent to the original term of PTE 2023–14, which expires on June 12, 2024, until the date the Department grants an exemption (if it determines the record supports the grant of a final exemption). These two periods are discussed more fully below.

Retroactive Relief Relating to the PTE 2023–14 Period

26. Section I(i) of PTE 2020–01 provides that each UBS QPAM must submit to an audit conducted by an independent auditor, who has been prudently selected and who has appropriate technical training and proficiency with ERISA and the Code, to evaluate the adequacy of, and each UBS QPAM's compliance with, the Policies and Training described herein. As UBS stated in its exemption application, “[t]he purpose of the independent audit is to give [Covered Plans] clients and the Department the confidence that the asset manager is complying with ERISA, and that continued exemptive relief is warranted.” Under this provision, the UBS QPAMs were required to complete an audit for the period from March 20, 2023 through March 19, 2024. However, PTE 2023–14 truncated this period due to the Merger, which was effective on June 12, 2023.

27. Section III(j)(1) of PTE 2023–14 requires the UBS QPAMs to complete an audit for the period from March 20, 2023 through June 12, 2023 (the beginning date of the one-year exemption provided in PTE 2023–14), which is referred to herein as the “stub period audit” within 180 days of June 12, 2023 (by December 9, 2023).¹⁴

Section III(j)(7) required the General Counsel or one of the three most senior executive officers of the UBS QPAM to which the audit report applies to certify the audit; Section III(j)(8), required the Risk Committee of UBS's Board of Directors to be provided with a copy of the Audit Report, and for a senior executive officer of UBS's Compliance and Operational Risk Control function to review the Audit Report for each UBS QPAM and certify in writing, under penalty of perjury, that such officer has reviewed the Audit Report; and III(j)(9) required each UBS QPAM to provide its certified Audit Report to the Department no later than 45 days following completion of the Audit Report (January 23, 2024). The Department required these audits in order to specifically and closely assess whether the UBS QPAMs remain insulated from the convicted UBS and Credit Suisse entities and could be trusted to safeguard plan assets, notwithstanding the convictions. On May 3, 2024, UBS' counsel notified the Department that UBS failed to complete the stub period audit report. UBS did not submit the certified audit report to the Department until May 10, 2024.

28. The record currently before the Department indicates that UBS did not engage the Independent Auditor, Fiduciary Counselors Inc, to complete the stub period audit until March 18, 2024, notwithstanding the fact that PTE 2023–14 required the audit to be completed by December 9, 2023, and for the audit report to be certified and submitted to the Department by January 23, 2024.¹⁵ UBS should have engaged an independent auditor well in advance of the dates set forth in Section III(j) of the exemption for the audit to be timely completed and for the audit report to be timely certified and submitted to the Department. Because it failed to meet this exemption condition, UBS did not comply with the requirements for relief

(PTE 2020–01) required an audit to be performed covering the period of March 20, 2023 through March 19, 2024. However, due to the timing of the merger (June 2024) the audit period shifted from a March-to-March cycle to a June-to-June cycle. Due to this shift, an audit was required for a “stub” period from the beginning of the March audit period on March 20, 2024, through the date of the merger on June 12, 2024. The audit requirement for this “stub” period was included in both the Department's proposed relief, and following a comment period, retained in the final exemption.

¹⁵ In a supplemental letter to the Department dated May 29, 2024, UBS' counsel informed the Department that the auditor notified UBS about the failure to complete the stub audit in January 2024, and the auditor sent a draft of the engagement letter to perform the audit to UBS on February 12, 2024. These events occurred before the Department received UBS' exemption application on February 23, 2024, and UBS should have disclosed them in its exemption application.

in PTE 2023–14 and engaged in non-exempt prohibited transactions for which it now requests relief.

29. In its exemption application, UBS stated that “. . . through independent audits required by the Department, the UBS QPAMs have proven, on an annual basis for many years, that they are in compliance with ERISA and protective of plan assets. In every category, and in every audit, the independent auditor has deemed that the UBS QPAMs met the terms of the exemption.” As stated above, however, based on the record, it appears that UBS became aware that the UBS QPAMs failed to complete the stub period audit report in January 2024, and did not notify the Department of this failure until May 3, 2024. The Department's exemption procedure regulation provides that “[w]hile an exemption application is pending final action with the Department, an applicant must promptly notify the Department in writing if he or she discovers that any material fact or representation contained in the application . . . is inaccurate, [or] if any such fact or representation changes during this period. . . .” Under the exemption procedure, UBS had an affirmative obligation to notify the Department of its failure to complete the stub period audit, and therefore to comply with a core condition of the exemption, well before it notified the Department on May 3, 2024.

30. Because the UBS QPAMs failed to comply with the audit conditions of the exemption, they lost the benefit of the relief provided by PTE 2023–14, and the Department is considering whether it should grant retroactive relief extending back to June 12, 2023 as part of this exemption, which would otherwise provide relief only from June 12, 2024 through June 11, 2029.¹⁶ The Department requests comments from UBS, the public, and interested parties on whether retroactive relief is appropriately including in this exemption, which would extend exemptive coverage to include the period from June 12, 2023 to June 11, 2024, as well as June 12, 2024 to June 11, 2029. In this connection, UBS should provide a detailed statement as to how a grant of retroactive relief would be consistent with the requirements for such relief as set forth in 29 CFR 2570.35(d).

31. The Department, however, will consider granting retroactive relief in connection with this proposal to the extent that UBS demonstrates to the Department that such relief is

¹⁶ The Department's requirements for retroactive relief are set forth in 29 CFR 2570.35(d).

¹⁴ The stub audit was required because UBS' audit cycle under its prior QPAM section I(g) five-year exemption that was in effect before the merger

appropriate in this exemption. In this connection, UBS should provide a detailed statement as to how it has satisfied the requirements for retroactive relief as set forth in 29 CFR 2570.35(d).

32. Specifically, for the Department to grant retroactive relief, UBS must explain how the Covered Plans were adequately safeguarded, notwithstanding UBS's failure to (1) contract with an auditor for the stub period audit and (2) timely certify, under penalty of perjury, that UBS reviewed this audit. The UBS QPAMs must also demonstrate that at a minimum that the UBS QPAMs: (i) ensured and will ensure that appropriate safeguards were established during the PTE 2023–14 Period to protect the interests of Covered Plan clients;¹⁷ (ii) Covered Plan clients were not harmed by non-exempt transactions during the PTE 2023–14 Period;¹⁸ (iii) a responsible plan fiduciary acted (and is acting) in good faith and took (and will take) appropriate steps that are necessary to protect the Covered Plans from abuse, loss, and risk during the PTE 2023–23 Period; and (iv) the UBS QPAMs have adjusted their policies and procedures in light of past failures to comply with PTE 2023–14 to ensure that such failures will not reoccur.¹⁹

33. The Department also invites comment from the UBS QPAMs, the independent auditor, UBS, and Covered Plans regarding whether UBS acted in good faith in engaging in the transactions permitted by PTE 2023–14, notwithstanding the fact that the UBS QPAMs, the independent auditor, and UBS failed to timely comply with an essential condition of the exemption.

34. The Department further requests UBS to provide detailed information to the Department regarding the costs and harms Covered Plans would occur if the Department does not grant retroactive relief for the period from June 12, 2023, to June 11, 2024. This detailed information should include, but not be limited to, a quantified estimate of the size of the losses Covered Plans would suffer if retroactive relief is not granted, and an explanation of the methodology UBS used to calculate these amounts and the underlying assumptions UBS used in its calculation. The Department notes that receipt of this explanation and detailed estimate of specific dollar amounts of the costs and harms is critical to its decision regarding whether it will grant retroactive relief to UBS.

Retroactive Period Relating to Filing Date of UBS' Exemption Application

35. As previously stated, PTE 2023–14 allowed the UBS QPAMs to continue to rely on the QPAM exemption for a one-year period following the Merger date notwithstanding the Convictions. This relief was necessary, because the relief granted to QPAMs before the Merger was no longer available on the effective date of the Merger. To receive further relief after the end of the one-period in PTE 2023–14, the UBS QPAMs would have to submit another exemption application to the Department to receive relief after the Merger.

36. The Department issued a clear statement to Covered Plan fiduciaries in the preamble to PTE 2023–14's proposal that clearly indicated that in order for the UBS QPAMs to receive relief beyond the one-year period in PTE 2023–14, they must submit sufficient written information to the Department substantially in advance of the expiration of the exemption's one-year term to permit the Department to make its requisite findings under ERISA section 408(a).²⁰ The Department also stated in that preamble that, it "is requesting detailed information from UBS and CSAG regarding the costs and harms to Covered Plans, if any, that could arise if the UBS QPAMs and the [CSAG QPAMs] can no longer rely on PTE 2020–01 and PTE 2022–01 following the Merger." Finally, the Department stated that, "if UBS and CSAG do not submit detailed and reliable information in this regard, the Department will not extend the relief [proposed] in this exemption beyond one year."²¹

37. The Department made these statements in the preamble to the notice of proposal for PTE 2023–14 to ensure that the UBS QPAMs were aware that they needed to submit their exemption application for extended relief sufficiently in advance of the expiration of the relief provided in PTE 2023–14 for the Department to be afforded with sufficient information and time to develop a complete required record upon which it could determine whether the Department could make its requisite findings under ERISA section 408(a) that UBS' requested exemptive relief is (1) administratively feasible, (2) in the interest of its Covered Plan clients, (3) and protective of the rights of its Covered Plan client's participants and beneficiaries.²²

²⁰ 88 FR 30785, 30786 (May 12, 2023).

²¹ *Id.* at 30788.

²² ERISA section 408(a) also requires the Secretary to publish a notice in the **Federal Register** of the pendency of an exemption, provide adequate

38. Nevertheless, UBS did not submit its application until February 22, 2024, and the application failed to convincingly establish the specific "costs and harms to Covered Plans," as requested by the Department in the preamble to proposed PTE 2023–14.²³ Further, as noted above, UBS and the UBS QPAMs failed to perform and certify the stub period audit in accordance with Section III(j) of PTE 2023–14, and did not disclose this failure in the February 22, 2024, exemption application which further complicated and delayed the Department's ability to review and resolve UBS' exemption application. For all these reasons, the Department has not been given sufficient information and time to develop a complete record, publish a proposed exemption with adequate public notice and comment, and issue a final exemption before the June 11, 2024 that grants all the requested exemptive relief prior to the expiration date provided in PTE 2023–14. In particular, the Department cannot make the required findings under ERISA section 408(a) that UBS' requested exemptive relief is (1) administratively feasible, (2) in the interest of its Covered Plan clients, (3) and protective of the rights of its Covered Plan clients' participants and beneficiaries, without additional submissions, public comments, and review.

39. Nonetheless, to protect Covered Plans, the Department is proposing to grant UBS retroactive relief from the date the Department publishes a final exemption (if granted) back to June 12, 2024, provided that UBS demonstrates, as part of the public notice and comment process, that the Department can make the required findings under ERISA Section 408(a) and that UBS will properly safeguard Covered Plans from harm. Since this retroactive relief period has not yet occurred, the Department also is requesting UBS to represent in a statement made in its comment response to this proposed exemption that it will continuously adhere to the conditions of PTE 2023–14 through the effective date of a final exemption (if granted). Moreover, to ensure that Covered Plans are adequately protected, the Department seeks comments from UBS and the public on whether it should grant retroactive relief for the period that would have been covered by PTE 2023–14, but for the failure to comply with the audit condition. As

notice to interested persons, and afford interested persons with an opportunity to comment on the proposed exemption.

²³ UBS did not provide this detailed information until May 2, 2024, a little more than a month from the expiration of PTE 2023–14.

¹⁷ 29 CFR 2570.35(d)(1)(i).

¹⁸ 29 CFR 2570.35(d)(1)(ii).

¹⁹ *Id.*

discussed below, the Department also proposes to add an additional condition designed to minimize the risk of future harm to Covered Plans.

Harm to Covered Plans in the Absence of QPAM Relief

40. Before it grants relief from ineligibility under PTE 84–14 Section I(g) due to a conviction or misconduct, the Department requires ineligible QPAMs to provide detailed statements that demonstrate and quantify the harms that Covered Plan clients would experience if the QPAMs were unable to rely on PTE 84–14 due to ineligibility. In its exemption application and in a response to a request for supplemental information from the Department, UBS provided the Department with the following estimates of the costs that each type of portfolio managed by the UBS QPAMs would incur if denied relief. The application assumed that Covered Plan assets would have to be liquidated because of the unavailability of PTE 84–14 with the following consequences for Covered Plans.²⁴

41. UBS Hedge Fund Solutions provides customized portfolios of hedge funds that are run as plan asset funds. UBS Hedge Fund Solutions manages approximately \$6.8 billion as part of this business. UBS estimated that these customized hedge fund portfolios would lose \$46.8 million if the covered plans liquidated their assets because the UBS QPAMs could not rely upon PTE 84–14. In calculating the estimates of losses in the event these portfolios were liquidated, UBS assumed that its clients would immediately request full redemptions and any current illiquid/side pocket investment would need to be sold in the secondary market at a 30 percent discount.

42. UBS Hedge Fund Solutions also provides investment advice to a private pension client that is invested in a customized portfolio of credit funds, including private credit funds. UBS Hedge Fund Solutions currently manages \$1.3 billion for this client. Due to the less liquid nature of these holdings, UBS estimates that it would take from two to six years to liquidate these holdings, or sometimes longer under the investments terms. UBS estimates that the costs of liquidation would be \$14.5 million. This estimate

assumes that any investment that would take five years or longer to be redeemed would be sold in the secondary market at a 30 percent discount.

43. UBS Hedge Fund Solutions is also a platform manager for select managed accounts with third party trading advisers. In this role, UBS Hedge Fund Solutions provides investment advice to pension clients as well as non-ERISA clients to invest in commingled managed accounts, which are run as plan asset funds. UBS Hedge Fund Solutions manages approximately \$406.6 million as part of this business. If UBS QPAMs are no longer allowed to rely on PTE 84–14, UBS estimated that the economic loss for these investors would be \$29.1 million. This estimate assumes the entire portfolio would be liquidated and the Covered Plan clients would pay the related transaction costs.

44. UBS also estimated the loss to active equity portfolios if UBS QPAMs were no longer able to rely on PTE 84–14. These equity portfolios cover large, small and mid-cap equity securities, and pursue a variety of strategies. Within these portfolios, UBS QPAMs managed approximately \$727 million in assets for ERISA plan clients. UBS estimates that liquidation costs for these portfolios would amount to approximately \$6.2 million based on a transaction cost model.

45. UBS offers a range of strategies across the global fixed income asset class spectrum. These strategies trade a variety of products, such as investment grade and non-investment grade debt securities, US treasuries, agency and non-agency mortgage-backed securities, and related derivatives. UBS QPAMs manage approximately \$1.1 billion in fixed income strategies for ERISA plan clients. If the Department does not grant an exemption, UBS estimates that the liquidation costs to these plans will be approximately \$3.84 million. To calculate these estimates, UBS constructed a bid/offer spread model based on the individual securities held in each client portfolio. The model assumes that liquidation will not occur during a time of market stress, and UBS suggests that the estimates may therefore be low.

46. UBS Investment Solutions²⁵ manages portfolios primarily based on a long-term, fundamental analysis, but may also employ different strategies as dictated by client investment guidelines and/or market conditions and may allow long and/or short positions in

markets, currencies, or other portfolio factors through the use of derivatives. UBS Investment Solutions may also employ long/short investment strategies that purchase securities on margin and/or sell securities short were permitted by client guidelines. UBS QPAMs manage approximately \$934 million in Investment Solutions strategies for ERISA plan clients.

47. If the Department does not grant an exemption, UBS estimates that liquidation costs for those portfolios will amount to \$358,907.

48. Credit Investments Group (CIG) is a business unit within UBS Asset Management Americas LLC. As part of its business, CIG manages an ERISA client account with a net asset value of \$109 million. In the event of a portfolio liquidation scenario, CIG would typically initiate what is effectively an auction process for every unique line item in the portfolio and invite various loan trading desks to bid on each asset. In this auction process, positions marked below 80 percent reasonably would be estimated to trade at least 10 percent below the current mark. Based on this, and other, assumptions, UBS estimates economic loss of \$2 million to the ERISA client's account in the event of liquidation.

49. In addition to the liquidation costs described above, UBS also represents that its Covered Plan clients would incur other costs associated with losing relief under PTE 84–14, such as costs of performing due diligence on a replacement manager, liquidating the legal entity, setting up a new legal entity with a replacement manager, building back a portfolio, losing capacity in closed or customized hedge funds, transferring positions, being out of the market, losing time invested for purposes of lock up periods, and costs associated with the paying commissions when a new manager sells the Covered Plans' current securities and buys new securities that it prefers. Hereinafter, these costs, and any other cost that may be incurred by a Covered Plan due to a UBS QPAM's loss of relief under PTE 84–14, other than a Liquidation Cost, is referred to as an additional cost.

Department's Request for Additional Information Regarding the Liquidation Costs and Additional Costs

50. The Applicant's representations imply that if the exemption is not granted, all affected Covered Plans will need to liquidate their investments. If that was not the Applicant's intent, the Department requests the Applicant to revise its Liquidation Costs estimates to reflect the view that not all Covered Plans would need to liquidate their

²⁴ The Department notes that UBS provided information not mentioned in this proposal regarding the potential losses to ERISA clients, but without clearly identifying the dollar amount of losses to plans in concrete terms. In such cases, the Department does not have enough information to include such representations in its findings. However, the information the Applicant provided that the Department can rely on is described below.

²⁵ It is the Department's understanding that UBS Investment Solutions is a team within UBS that manages portfolios based on an asset allocation investment process.

investments if the exemption is not granted, along with the methodology the Applicant used to provide the estimates, and the factors that may affect those estimates.

51. Section III(k)(2) of PTE 2023–14 requires that any arrangement, agreement, or contract between the UBS QPAMs and Covered Plans, include an obligation for the QPAM to indemnify and hold harmless Covered Plans from actual losses. This includes the losses and related costs arising from unwinding transactions with third parties and from transitioning Covered Plan assets to an alternative asset manager as well as costs associated with any exposure to excise taxes under Code section 4975 as a result of a QPAM's inability to rely upon the relief in PTE 84–14.²⁶

52. Accordingly, it is unclear why the Covered Plans would incur the Liquidation Costs and Additional Costs identified by the Applicant, in the event relief were not granted. To the extent the Applicant does not believe Covered Plans are contractually protected from these costs, the Department requests comment from the Applicant identifying and describing the extent to which the Liquidation Costs and/or Additional Costs are outside the scope of Section III(k)(2), and the Applicant's explanation of why such costs are outside the scope of Section III(k)(2).

53. The Department also requests comments on whether there are other potential costs or benefits associated with the failure to grant retroactive relief that are not addressed by the questions above. For example, what impact would the denial of retroactive relief have on the willingness of parties to rely on the QPAM exemption in the future? To what extent is the denial of retroactive relief proportionate or disproportionate with the failure of the

exemptions of PTE 2023–14? Are there other issues or considerations that the Department should address before making a determination on retroactive relief?

Audits of Credit Suisse

54. Newport Trust Company (Newport) conducted the audits of Credit Suisse Asset Management, LLC (CSAM LLC) before the merger between UBS and Credit Suisse AG. The most recent PTE 2022–01 required UBS to submit to an audit by an independent auditor for the period of November 21, 2022, to June 11, 2023. In its audit report Newport determined that CSAM was in compliance with the terms and conditions of PTE 2022–01. Moreover, Newport had no recommendations to strengthen the Exemption Review by the Compliance Officer or any new recommendations to strengthen CSAM LLC's exemption compliance program, or any recommendation specific to the Policies or Training.

55. Newport represents in its latest audit report that it conducted a thorough due diligence process to conduct the audit and issue the report for the covered period. Its examination involved ongoing contact with representatives of CSAM, reviews of the Policies and Training, testing of data related to Plan accounts, review of collected data, testing of CSAM's operational compliance with the Policies and Training, and preparation of the Audit Report.

In making its determinations, Newport:

(1) reviewed the following Policies and evaluated their adequacy during the Covered Period—CSAM's ERISA Compliance Manual, including appendices on PTE 2022–01, Parties in Interest, and QPAM Compliance Guidance; “Handling of ERISA Related MyIncidents Procedure;” and CSAM's best execution policy. Numerous CSAG risk policy publications, including policies on data management, policies governing interactions with and exchange of information with regulators, government agencies, and legislative bodies; global regulatory reporting accountability policy; records management global policy; policy prohibiting certain persons serving as employee, officers or directors of Credit Suisse affiliates.

(2) gathered and reviewed extensive documentation and information from CSAM to determine compliance with the terms of the exemption—including marketing materials, numerous internal and external written correspondence, correspondence with regulators (including Forms ADV for CSAM), financial documents, balance sheets, records of best execution, internal announcements, compliance records from CSAG compliance systems, trading records and spreadsheets detailing corrections of

trading errors; copies of notices required under PTE 2022–01 and prior exemptions, personnel files, sample internal documents, etc.

(3) reviewed updates to the Training program content and anticipated content for upcoming online training;

(4) reviewed the Annual Exemption Review and report completed by the Compliance Officer (“Annual Exemption Report”) and evaluated its adequacy; and

(5) developed tests to evaluate CSAM's operational compliance with the Policies, including manager independence, ERISA compliance, communications with regulators and Plan/IRA clients, and Exemption compliance and corrections during the Covered Period, with particular focus on class actions and complying with limits on employer securities.

Newport also validated that certain follow-up actions from its preceding audit were completed.

Audits of UBS

56. Fiduciary Counselors Inc. (FCI) conducted the audits of UBS QPAMs pursuant to PTE 2020–01. FCI confirmed that the UBS QPAMs fulfilled the terms and conditions of the exemption during the audit periods of February 20, 2020 through March 19, 2021; March 20, 2021 to March 19, 2022; March 20, 2022 to March 19, 2023; and March 20, 2023 to June 11, 2023. FCI also concluded that the QPAMs' policies and procedures are reasonably designed to ensure that each QPAM continues to operate in a manner compliant with ERISA and the requirements of the exemption.

57. During the course of the audits performed since the effective date of PTE 2020–01, Fiduciary Counselors Inc. reviewed the following:

(1) marketing materials directed to Covered Plans, investment committee minutes, client complaints, compliant policies, broker dealer reports, billing records, and consent forms for PTE 77–4, Compliance Office Exemption Reports, ADV Forms, gifts and entertainment policies, performance reports and disclosures;

(2) trading system, guideline breaches and ERISA breach hardcoding process in trading system, any guideline breaches and correspondence files associated with the breaches.

(3) client adoption process.

(4) compliance with the following PTE 84–14 requirements: power to appoint rule, the 20% rule, that the counterparty is not a UBS QPAM or a person related to the UBS QPAM, the transaction is not an excluded transaction, shareholders' or partners' equity of the QPAM is at least \$1 million, and total client assets under management and control of the QPAM/investment adviser is at least \$85 million.

(5) whether required notices under PTE 2020–01 were sent timely and appropriately, whether additional communications are sent

²⁶ PTE 2023–14, Section III, Condition (k) states, in part, “. . . with respect to any arrangement, agreement, or contract between an Affiliated QPAM and a Covered Plan, the QPAM agrees and warrants to Covered Plans . . . (2) To indemnify and hold harmless the Covered Plan for any actual losses resulting directly from the QPAM's violation of ERISA's fiduciary duties, as applicable, and of the prohibited transaction provisions of ERISA and the Code, as applicable; a breach of contract by the QPAM; or any claim arising out of the failure of such QPAM to qualify for the exemptive relief provided by PTE 84–14 as a result of a violation of Section I(g) of PTE 84–14, other than a Conviction covered under this exemption. This condition applies only to actual losses caused by the QPAM's violations. The term Actual Losses includes, but is not limited to, losses and related costs arising from unwinding transactions with third parties and from transitioning Plan assets to an alternative asset manager as well as costs associated with any exposure to excise taxes under Code section 4975 as a result of a QPAM's inability to rely upon the relief in the QPAM Exemption;”

in a timely manner, and whether training was held in a timely manner.

(6) proof of training, content of training; proof of ethics training, training of new hires, conduct interviews with portfolio managers regarding effectiveness of training and suggested improvements, online training modules, training system and process of assigning courses to employees and process for employees completing assigned training.

(7) the written Exemption Report prepared by the Compliance Officer for compliance with the requirements of PTE 2020–01.

58. FCI also validated that certain follow-up actions from its preceding audit were completed. Namely, in its prior audit report, FCI recommended that the UBS QPAMs develop processes to identify affiliates of the party in interest with the authority to appoint or terminate the QPAM or negotiate the terms of the QPAM's management agreement with the plan.

New Conditions in the Proposed Exemption

59. By failing to comply with the audit requirement in PTE 2023–14, the Applicant breached a core protective condition of the exemption. In order to address this failure and to prevent its reoccurrence or the occurrence of any additional failures, the Department is proposing to add additional conditions to those it included in PTE 2023–14. The first new proposed condition in Section III(v)(4) of the proposed exemption would require each UBS QPAM to develop written processes that clearly describe: (1) how the QPAM identifies and quantifies “actual losses” for purposes of Section III(j)(2); and (2) how Covered Plans may recover or avoid incurring the losses that the UBS QPAM must indemnify or hold Covered Plans harmless from incurring pursuant to Section III(j)(2). Each UBS QPAM must develop these processes within 30 days after the date the Department publishes a final exemption in the **Federal Register**. Furthermore, the Department is adding clarifying language to Section III(j)(2) to better articulate its longstanding position regarding the scope of QPAMs’ “hold harmless” obligations. In this regard, the Department is adding text to clarify that a “violation of any conditions of this exemption” triggers the “hold harmless” obligations of a QPAM under that section. That language also appears in certain other places throughout the proposal where relevant.

60. The second new proposed condition in Section III(t) provides that if the independent auditor or UBS or its affiliates learns of any material noncompliance with a condition of this exemption, UBS must send a notice (a Violation Notice) to all affected Covered

Plans and the Department that prominently and conspicuously states or describes: (1) UBS, or the UBS QPAM, as applicable, failed to meet the terms of this exemption (and describe the failure); (2) the extent to which UBS QPAMs have potentially been operating without an exemption due to the failure; (3) whether UBS plans to apply for retroactive relief from the Department for this failed condition; (4) any further transactions engaged in by the UBS QPAMs on behalf of Covered Plans that may be non-exempt prohibited transactions unless the Department grants retroactive relief for the period in which the transactions occurred; and (5) UBS must indemnify and hold harmless the Covered Plan for: any actual losses resulting directly from the QPAM's failure to comply with any conditions of this exemption, ERISA's fiduciary duties and of the prohibited transaction provisions of ERISA and the Code, a breach of contract by the QPAM, or any claim arising out of the failure of such QPAM to qualify for the exemptive relief provided by PTE 84–14 as a result of a violation of PTE 84–14 Section I(g), other than a Conviction covered under the exemption. The Violation Notice must be sent to all affected Covered Plans and the Department within 14 days of discovering the violation. The Department's objective in proposing a requirement that UBS send the Violation Notice to its Covered Plan clients is to provide the Covered Plan clients with the opportunity to make informed and prudent decisions regarding the protection of plan assets. The Department requests comment on whether the Violation Notice is sufficiently protective of the interests of the Client Plans and their participants and beneficiaries. In that context, the Department is interested in receiving comments discussing whether additional disclosure or a requirement for additional oversight by an independent fiduciary may be necessary to ensure that the exemption is sufficiently protective of the Client Plans and their participants and beneficiaries.

The Proposed Exemption

61. As stated above, the Department is proposing this exemption to protect Covered Plans from the costs and harms that would arise if the UBS QPAMs no longer were able to rely on the relief provided in PTE 84–14. If the proposed exemption is granted, the UBS QPAMs would not be precluded from relying on the exemptive relief provided by PTE 84–14, notwithstanding the Covered

Convictions.²⁷ This proposed exemption would be effective for a five-year period beginning on June 12, 2024, and ending on June 11, 2029, if the Applicant satisfies the requirements of the Proposed Exemption at all times.

Expiration of Exemption

62. If UBS satisfies all the conditions of this exemption, its relief under this exemption as proposed will expire on June 11, 2029. UBS and its underlying entities, as well as Covered Plan fiduciaries, are cautioned that the Department may not extend this five-year exemption following its expiration due to the significant number of convictions and the seriousness of the underlying conduct of the tainted entities within the UBS corporate umbrella following the five year term unless, among other things, UBS submits a complete and accurate application with detailed written information to the Department by December 14, 2027. This will ensure that the Department has sufficient time to analyze the exemption application to ensure it provides sufficient information for the Department to make its findings under ERISA Section 408(a), publish a notice of proposed exemption with a sufficient notice and comment period, consider comments received on the proposed exemption, and publish a notice of final exemption (if appropriate based on the entire record).

Summary of the Exemption's Protective Conditions

63. In developing administrative exemptions under ERISA section 408(a), the Department implements its statutory directive to grant only exemptions that are appropriately protective and in the interest of, affected plans and IRAs. The Department is proposing this exemption with conditions that would protect Covered Plans (and their participants and beneficiaries) and allow them to continue to benefit from the transactions described in PTE 84–14.²⁸ The Department notes that this exemption includes most of the conditions it imposed upon CSAG and UBS in their most recent individual exemption, PTE 2023–14, but the Department has made

²⁷ Section I(g) of PTE 84–14 generally provides that a QPAM is ineligible to rely on PTE 84–14 for 10 years following a Criminal Conviction, or participation in Prohibited Misconduct (as both are defined in PTE 84–14), of the QPAM, any affiliate thereof, or any direct or indirect owner of a five percent or more interest in the QPAM, subject to the Ineligibility Date in Section I(h).

²⁸ The Department notes that this is a summary of the conditions intended for the convenience of a reader; however, the governing conditions for the exemptive relief are those reflected in the operative text in Section III of the proposed exemption.

minor changes and added additional conditions that are described below.

64. Misconduct Entity.

Notwithstanding that the 2013 UBS Conviction is no longer within the 10-year period of disqualification period under Section I(g), the proposal requires that the UBS QPAMs continue to be completely insulated from any aspect of the business activities of UBS Securities Japan. Because the same criminal activity (which relates to the fraudulent submission of Yen LIBOR rates during roughly the same time period) underpins both the 2013 UBS Conviction, and the 2017 UBS Conviction, there is not a valid reason for the Department to require the UBS QPAMs to be insulated from UBS while it permits the UBS QPAMs to engage in transactions with UBS Securities Japan. Therefore, the Department has broadened the definition of “Misconduct Entity” in PTE 2023–14 to include UBS Securities Japan. Furthermore, although the FX Misconduct itself did not violate Section I(g), the misconduct led to the DOJ’s determination that UBS had breached the LIBOR NPA. The FX Misconduct was itself egregious enough to raise concerns that the UBS QPAMs should be completely insulated from any entity involved in that misconduct. However, because UBS is already a Misconduct Entity by virtue of the 2017 UBS Conviction, no updates to the definition is required.

65. Criminal Activity. For reasons similar to those articulated in the prior paragraph, the Department has determined that each instance of the Criminal Activity is equally concerning notwithstanding that the 2013 UBS Conviction and the FX Misconduct do not in themselves trigger a disqualification of the UBS QPAMs from relying on PTE 84–14. As such, the Department has drafted certain exemption conditions to ensure that the UBS QPAMs continue to be fully insulated from the personnel that were involved in the misconduct related to the Criminal Activity. Therefore, the Department maintains in the proposal the approach it took in the PTE 2023–14 conditions where it refers to the Covered Convictions and the FX Misconduct. However, the Department uses the defined term Criminal Activity in this proposal, because the 2013 UBS Conviction is technically no longer included in the definition of “Covered Convictions” due to the expiration of the ten-year ineligibility period.

66. UBS Seconded Employees. In prior exemptions, UBS and Credit Suisse had requested a carve-out from the exemption conditions for services

provided by individuals that are considered to be employed by a Misconduct Entity for payroll and certain administrative purposes. Applicants in those exemptions referred to these employees as being “seconded” or “double-hatted.” The Department has proposed a new definition of “UBS Seconded Employee” in Section I(j) of the proposal to avoid using ambiguous terms such as “double-hatted” and to ensure that no employees of Misconduct Entities are involved in the UBS QPAMs’ business activities, except to the extent that such employees are subject to the control and supervision of the UBS QPAMs. The new definition of UBS Seconded Employee is included in the conditions where references to “double-hatted” and “seconded” employees previously appeared in PTE 2023–14. New Section I(j) provides that a “UBS Seconded Employee” means “an individual nominally employed by UBS who performs work on behalf of a UBS QPAM; provided that such UBS QPAM is solely responsible for the management and control of the employee’s job activities performed on behalf of such QPAM. Notwithstanding the preceding sentence, the UBS QPAM must be solely responsible for the establishment of the employee’s job duties and terms of employment (including compensation, promotions, and benefits) and must have supervisory responsibility with respect to, among other things, the employee’s performance, training, and disciplinary actions.” The Department is requesting that the Applicant’s comment includes a representation that demonstrates how this arrangement remains protective of Covered Plans following the merger.

67. The UBS QPAMs (including their officers, directors, agents (with very narrow exceptions), employees of such QPAMs, and UBS Seconded Employees) must not have known, have reason to know of, nor participated in the criminal conduct that is the subject of any of the Criminal Activity. Each UBS QPAM (and its officers, directors, etc.) must meet this condition with respect to each element of Criminal Activity regardless of whether the misconduct occurred within the QPAM’s corporate umbrella at the time it occurred. Further, any other party engaged on behalf of the UBS QPAMs who had responsibility for or exercised authority in connection with the management of plan assets must not have known, had reason to know of, nor participated in the Criminal Activity. Again, each Affiliated and Related QPAM (and their officers, directors, etc.) must comply with this prohibition, regardless of

whether the criminal misconduct occurred within the QPAM’s corporate umbrella at the time the Criminal Activity occurred.

68. The proposed exemption continues the requirement from PTE 2023–14 that no UBS QPAM (including their officers, directors, agents other than one of the entities subject to a Covered Conviction, employees of such QPAMs, and UBS Seconded Employees) received direct compensation, or knowingly received indirect compensation, in connection with the criminal conduct that is the subject of the Criminal Activity. Further, no other party engaged on behalf of the UBS QPAMs who had responsibility for, or exercised authority in connection with the management of plan assets received direct compensation, or knowingly received indirect compensation, in connection with the criminal conduct of that is the subject of the subject of the Criminal Activity.

69. The protective conditions contained in this proposed exemption include a requirement that precludes each Affiliated QPAM from employing or knowingly engaging any of the individuals who participated in the criminal conduct underlying the Criminal Activity. This means that no individual who participated in criminal misconduct at either UBS, UBS Securities Japan, UBS France, CSAG, or CSSEL (each, a Misconduct Entity) may be employed by any Affiliated QPAM, regardless of whether the Misconduct Entity was outside the QPAM’s corporate umbrella at the time of the misconduct. A UBS QPAM also must not have exercised authority over the assets of any Covered Plan client in a manner that it knew or should have known would further the criminal conduct underlying the Criminal Activity; or cause the UBS QPAM or its affiliates to directly or indirectly profit from the criminal conduct underlying the Criminal Activity.

70. Under this exemption, no Affiliated QPAM will use its authority or influence to direct an “investment fund” (as defined in Section VI(b) of PTE 84–14) that is subject to ERISA or the Code and managed by such Affiliated QPAM with respect to one or more Covered Plans, to enter into any transaction with a Misconduct Entity or to engage a Misconduct Entity to provide any service to such investment fund, for a direct or indirect fee borne by such investment fund, regardless of whether such transaction or service may otherwise be within the scope of relief provided by an administrative or statutory exemption. This condition provides exceptions for the provision of:

(1) certain sub-custodial services by an affiliate of UBS that is selected by an unaffiliated global custodian that, in turn, is selected by someone other than a UBS QPAM; and (2) services provided by UBS Seconded Employees. Further, other than with respect to employee benefit plans maintained or sponsored for its own employees or the employees of an affiliate, a Misconduct Entity may not act as a fiduciary within the meaning of ERISA section 3(21)(A)(i) or (iii), or Code section 4975(e)(3)(A) and (C), with respect to Covered Plan assets.

71. Each Affiliated QPAM must continue to maintain, adjust to the extent necessary, implement, and follow written policies and procedures (the Policies) that are reasonably designed to ensure that: (a) the asset management decisions of the Affiliated QPAM are conducted independently of each Misconduct Entity's corporate management and business activities; (b) the Affiliated QPAMs fully comply with ERISA's fiduciary duties and with ERISA's and the Code's prohibited transaction provisions; (c) the Affiliated QPAMs do not knowingly participate in any other person's violation of ERISA or the Code with respect to Covered Plans; (d) any filings or statements made by the Affiliated QPAMs to regulators on behalf of, or in relation to, Covered Plans are materially accurate and complete; (e) the Affiliated QPAMs do not make material misrepresentations or omit material information in their communications with such regulators, or in their communications with Covered Plans; and (f) the Affiliated QPAMs comply with the terms of the exemption.

72. This proposed exemption requires each Affiliated QPAM to maintain, adjust to the extent necessary, and implement a training program (the Training) that will be conducted at least annually for all relevant asset/portfolio management, trading, legal, compliance, and internal audit personnel. The Training must cover, at a minimum, the Policies, ERISA and Code compliance, ethical conduct, the consequences that would result from not complying with the proposed exemption conditions, and the requirement to promptly report wrongdoing.

73. This proposed exemption requires each Affiliated QPAM to continue to engage an independent auditor annually to evaluate the adequacy of, and the QPAM's compliance with, the Policies and Training required by the exemption. The independent auditor must be prudently selected by the Affiliated QPAMs and have appropriate technical training and proficiency with ERISA and the Code to perform the tasks

required by the exemption. The Affiliated QPAMs must grant the auditor unconditional access to their business, and the auditor's engagement must specifically require the auditor to test each Affiliated QPAM's operational compliance with the Policies and Training.

74. The independent auditor must issue a written audit report (the Audit Report) annually to UBS and the Affiliated QPAM to which the audit applies, that describes the procedures performed by the auditor in connection with its examination. Further, the Affiliated QPAMs must promptly address any instance of noncompliance identified by the auditor and must promptly address or prepare a written plan of action to address any determination as to the adequacy of the Policies and Training and the auditor's recommendations, if any, with respect to strengthening the Policies and Training of the respective Affiliated QPAM. The Audit Report must be provided to the Department annually by the Affiliated QPAM, and the Department will make the Audit Report part of the public record each year regarding this five-year exemption.

75. This proposed exemption further requires the General Counsel, or one of the three most senior executive officers of the Affiliated QPAM to which the Audit Report applies, to certify in writing and under penalty of perjury that the officer has reviewed the Audit Report and the exemption, and the Affiliated QPAM has addressed, corrected, and remedied (or has an appropriate written plan to address) any identified instance of noncompliance or inadequacy regarding the Policies and Training identified in the Audit Report.

76. With respect to any arrangement, agreement, or contract between an Affiliated QPAM and a Covered Plan, this proposal requires each Affiliated QPAM to agree and warrant: (a) to comply with ERISA and the Code, including the standards of prudence and loyalty set forth in ERISA section 404; (b) to refrain from engaging in prohibited transactions that are not otherwise exempt; (c) to indemnify and hold harmless the Covered Plan for any actual losses resulting directly from, among other things, the Affiliated QPAM's violation of the conditions for this exemption, prohibited transactions, and ERISA's fiduciary duties; (d) with narrow exceptions, to not restrict the ability of such Covered Plan to terminate or withdraw from its arrangement with the Affiliated QPAM with respect to any investment in a separately managed account or pooled fund subject to ERISA and managed by

such QPAM; (e) with narrow exceptions, to not impose any fees, penalties, or charges for such termination or withdrawal; and (f) to not include exculpatory provisions disclaiming or otherwise limiting the liability of the Affiliated QPAM for a violation of such agreement's terms.

77. Each Affiliated QPAM must provide a notice of its obligations under this exemption to each applicable Covered Plan, by the dates specified in the exemption. Each Affiliated QPAM also must provide to each applicable sponsor and beneficial owner of a Covered Plan a copy of the proposal and final notice of the exemption as published in the **Federal Register**, a separate summary describing the facts that led to each Conviction, and a prominently displayed statement that each Conviction results in a failure to meet a condition in PTE 84-14 and an individual exemption, which must be identified, by the dates specified in the exemption.

78. This proposed exemption requires each Affiliated QPAM to maintain a designated senior compliance officer (the Compliance Officer) who will be responsible for compliance with the Policies and Training requirements described in this proposed exemption. The Compliance Officer must conduct a review, for the twelve-month period specified below (the Exemption Review), to determine the adequacy and effectiveness of the implementation of the Policies and Training and issue a written report (the Exemption Report) on the findings.

79. This proposed exemption requires UBS to impose internal procedures, controls, and protocols on each Misconduct Entity to reduce the likelihood of any recurrence of conduct that is the subject of the Criminal Activity.

Statutory Findings

80. ERISA section 408(a) provides, in part, that the Department may not grant an exemption unless the Department finds that the exemption is administratively feasible, in the interest of affected plans and of their participants and beneficiaries, and protective of the rights of such participants and beneficiaries. These criteria are discussed below.

81. "*Administratively Feasible.*" The Department has tentatively determined that the proposal is administratively feasible for the Department, because among other things, a qualified independent auditor will be engaged by the Affiliated QPAM to perform an in-depth annual audit covering each Affiliated QPAM's compliance with the

terms of the exemption, and a corresponding written audit report will be provided to the Department and be made available to the public. Further, detailed periodic reports will be made to the Department and to Covered Plan fiduciaries.

82. *“In the interest of.”* The Department has tentatively determined that the proposed exemption is in the interests of the participants and beneficiaries of affected Covered Plans. The Department understands based on representations from the Applicant, that if the requested exemption is denied, Covered Plans may be forced to find other managers and may be deprived of the investment management services that these plans expected to receive when they appointed these managers. Loss of the exemption could result in the termination of relationships that the fiduciaries of the Covered Plans have determined to be in the best interests of those plans, even after the disclosures of the earlier Covered Convictions, the 2013 UBS Conviction, and the FX Misconduct pursuant to the individual exemptions the managers previously received. Additionally, the independent audit, while untimely performed, found no other violation by the UBS QPAMs of the terms of PTE 2023–14.

83. *“Protective of.”* The Department has tentatively determined that the proposed exemption is protective of the interests of the participants and beneficiaries of affected Covered Plans. As described above, the proposed exemption imposes a suite of affirmative requirements and obligations upon the Affiliated QPAMs that include but are not limited to: (a) the maintenance of the Policies; (b) the maintenance of the Training; (c) a robust audit conducted by a qualified independent auditor; (d) the provision of certain agreements and warranties on the part of the Affiliated QPAMs; (e) specific notices and disclosures concerning the circumstances necessitating the need for exemptive relief and the Affiliated QPAMs’ obligations under this proposed exemption; and (f) the designation of a Compliance Officer with responsibility to ensure compliance with the Policies and Training requirements under this proposed exemption, and the Compliance Officer’s completion of an Exemption Review and corresponding Exemption Report. The Department notes that this exemption includes all conditions imposed upon UBS in PTE 2023–14 as well as certain modifications described above designed to enhance the protections required for Covered Plans.

Summary

84. This proposed five-year exemption would provide prospective relief from certain restrictions set forth in ERISA section 406 and Code Section 4975(c)(1). No relief or waiver of a violation of any other law is provided by the exemption. The relief in this proposed five-year exemption would terminate in the event that an entity within the UBS corporate structure is convicted of any crime covered by PTE 84–14 Section I(g) (other than a Covered Conviction), or any term of PTE 84–14, as amended, is violated. In such event, and as described above, the UBS QPAMs would have to comply with the requirements of amended PTE 84–14 for additional relief.

85. When interpreting and implementing this exemption, the Applicant and the relevant QPAM should resolve any ambiguities considering the exemption’s protective purposes. To the extent additional clarification is necessary, these persons or entities should contact EBSA’s Office of Exemption Determinations by email (e-oed@dol.gov) or phone (202–693–8540).

86. Based on the conditions that are included in this proposed exemption, the Department has tentatively determined that the prospective relief sought by the Applicant would satisfy the statutory requirements for an individual exemption under ERISA section 408(a) and Code section 4975(c)(2) if the Applicant submits sufficient additional information the Department is requiring the Applicant to provide in its comment response to this proposed exemption.

87. This exemption proposes conditions that would apply during the five-year period from June 12, 2024, to June 11, 2029. In addition, and as explained in detail above, the Department seeks comments on whether to include retroactive relief for the period between June 12, 2023 to June 12, 2024 (the PTE 2023–14 Period). In order for the Department to determine whether UBS should receive retroactive relief during the PTE 2023–14 Period, UBS must provide a detailed statement in a comment to this proposed exemption that demonstrates a grant of retroactive relief would be consistent with the Department’s requirements for such relief as set forth in 29 CFR 2570.35(d) during the PTE 2023–14 Period.

Notice to Interested Persons

UBS will provide notice of this proposed exemption to its Covered Plan clients by first class mail or email

within two days after the publication of the notice of proposed exemption in the **Federal Register**. The notice of this proposed exemption will contain a supplemental statement, as required pursuant to 29 CFR 2570.43(a)(2) and a Summary the Proposed Exemption which includes information regarding the non-compliance in the PTE 2023–14 Period. The supplemental statement will inform interested persons of their right to comment on and to request a hearing with respect to the pending exemption. Written comments and hearing requests are due within 32 days after publication of this notice of proposed exemption in the **Federal Register**. The Department will make all comments available to the public.

Warning:

If you submit a comment, EBSA recommends that you include your name and other contact information in the body of your comment, but DO NOT submit information that you consider to be confidential, or otherwise protected (such as Social Security number or an unlisted phone number) or confidential business information that you do not want publicly disclosed. All comments may be posted on the internet and can be retrieved by most internet search engines.

General Information

The attention of interested persons is directed to the following:

(1) The fact that a transaction is the subject of an exemption under ERISA section 408(a) and/or Code section 4975(c)(2) does not relieve a fiduciary or other party in interest or disqualified person from certain other provisions of ERISA and/or the Code, including any prohibited transaction provisions to which the exemption does not apply and the general fiduciary responsibility provisions of ERISA section 404, which, among other things, require a fiduciary to discharge his duties respecting the plan solely in the interest of the participants and beneficiaries of the plan and in a prudent fashion in accordance with ERISA section 404(a)(1)(B); nor does it affect the requirement of Code section 401(a) that the plan must operate for the exclusive benefit of the employees of the employer maintaining the plan and their beneficiaries;

(2) Before an exemption may be granted under ERISA section 408(a) and/or Code section 4975(c)(2), the Department must find that the exemption is administratively feasible, in the interests of the plan and of its participants and beneficiaries, and

protective of the rights of participants and beneficiaries of the plan;

(3) The proposed exemption, if granted, will be supplemental to, and not in derogation of, any other provisions of ERISA and/or the Code, including statutory or administrative exemptions and transitional rules. Furthermore, the fact that a transaction is subject to an administrative or statutory exemption is not dispositive of whether the transaction is in fact a prohibited transaction; and

(4) The proposed exemption, if granted, will be subject to the express condition that the material facts and representations contained in each application are true and complete, and that each application accurately describes all material terms of the transaction which is the subject of the exemption.

Proposed Five-Year Exemption

The Department is considering granting this five-year exemption under the authority of ERISA section 408(a) and Internal Revenue Code (or Code) section 4975(c)(2), and in accordance with the procedures set forth in 29 CFR part 2570, subpart B (89 FR 4662, January 24, 2024)).²⁹ Effective December 31, 1978, section 102 of Reorganization Plan No. 4 of 1978, 5 U.S.C. App. 1 (1996), transferred the authority of the Secretary of the Treasury to issue exemptions of the type requested to the Secretary of Labor. Therefore, this notice of proposed exemption is issued solely by the Department.

Section I. Definitions

(a) Names of Certain Corporate Entities:

(1) The term “CSAG” means Credit Suisse AG, which was 100% owned by Credit Suisse Group AG, before UBS AG acquired Credit Suisse Group AG.

(2) The term “CSAM LLC” means Credit Suisse Asset Management, LLC. On May 1, 2024, CSAM LLC was merged into UBS Americas, with UBS Americas as the surviving entity.

(3) The term “CSSEL” means Credit Suisse Securities (Europe) Limited an indirectly a wholly owned subsidiary of UBS Group AG.

(4) The term “UBS” means UBS AG which is a wholly owned subsidiary of UBS Group AG.

(5) The term “UBS Americas” means UBS Asset Management (Americas) LLC and is wholly owned by UBS Americas, Inc., a wholly owned subsidiary of UBS AG.

(6) The term “UBS Europe” means UBS Europe SE. UBS Europe is the successor to UBS (France) S.A. UBS (France) S.A. was a wholly owned subsidiary of UBS under the laws of France until 2023. In July of 2023, UBS France S.A. merged into UBS Europe and set up a branch in France called UBS Europe SE France Branch.

(7) The term “UBS Hedge Fund Solutions LLC” was formerly known as UBS Alternative and Quantitative Investments, LLC and is wholly owned by UBS Americas Holding LLC, a wholly owned subsidiary of UBS.

(8) The term “UBS Securities Japan” means UBS Securities Japan Co. Ltd, a wholly owned subsidiary of UBS incorporated under the laws of Japan.

(b) The term “Affiliated QPAM” means: UBS Americas and UBS Hedge Fund Solutions LLC, and any future entity within the Asset Management or the Global Wealth Management Americas U.S. divisions of UBS that qualifies as a “qualified professional asset manager” (as defined in Section VI(a) of PTE 84–14) and that relies on the relief provided by PTE 84–14, and with respect to which UBS is an “affiliate” (as defined in Part VI(d) of PTE 84–14).³⁰ The term Affiliated QPAM excludes a Misconduct Entity.

(c) The term “Criminal Activity” means the Covered Convictions, the 2013 UBS Conviction, and the FX Misconduct.

(d) The term “Covered Convictions” means (1) the judgment of conviction against CSAG for one count of conspiracy to violate section 7206(2) of the Internal Revenue Code in violation of Title 18, United States Code, Section 371, that was entered in the District Court for the Eastern District of Virginia in Case Number 1:14-cr-188-RBS, on November 21, 2014 (the “2014 CSAG Conviction”); (2) the judgment of conviction against CSSEL in Case Number 1:21-cr-00520-WFK (the “2022 CSSEL Conviction”); (3) the judgment of conviction against UBS in case number 3:15-cr-00076-RNC in the U.S. District Court for the District of Connecticut for one count of wire fraud in violation of Title 18, United States Code, Sections 1343 and 2 in connection with UBS’s submission of Yen London Interbank Offered Rates and other benchmark interest rates between 2001 and 2010; and (4) the judgment of conviction on February 20, 2019, against UBS and UBS France in

case Number 1105592033 in the French First Instance Court (the “2019 UBS France Conviction”).

(e) The term “2013 UBS Conviction” means the judgment of conviction against UBS Securities Japan Co. Ltd. in case number 3:12 cr 00268 RNC in the U.S. District Court of the District of Connecticut for one count of wire fraud in violation of Title 18, United States Code, sections 1343 and 2 in connection with submission of YEN London Interbank Offered Rates and other benchmark interest rates.

(f) The term “FX Misconduct” means the conduct engaged in by UBS personnel described in Exhibit 1 of the Plea Agreement (Factual Basis for Breach) entered into between UBS and the Department of Justice Criminal Division, on May 20, 2015, in connection with Case Number 3:15-cr-00076-RNC filed in the US District Court for the District of Connecticut.

(g) The term “Covered Plan” means a plan subject to Part IV of Title I of ERISA (an “ERISA-covered plan”) or a plan subject to Code section 4975 (an “IRA”), in each case, with respect to which an Affiliated QPAM relies on PTE 84–14, or with respect to which an Affiliated QPAM (or any UBS affiliate) has expressly represented that the manager qualifies as a QPAM or relies on PTE 84–14. A Covered Plan does not include an ERISA-covered plan or IRA to the extent the Affiliated QPAM has expressly disclaimed reliance on QPAM status or PTE 84–14 in entering into a contract, arrangement, or agreement with the ERISA-covered plan or IRA. Notwithstanding the above, an Affiliated QPAM may disclaim reliance on QPAM status or PTE 84–14 in a written modification of a contract, arrangement, or agreement with an ERISA-covered plan or IRA, where the modification is made in a bilateral document signed by the client; the client’s attention is specifically directed toward the disclaimer; and the client is advised in writing that, with respect to any transaction involving the client’s assets, the Affiliated QPAM will not represent that it is a QPAM, and will not rely on the relief described in PTE 84–14.

(h) The term “Exemption Period” means the period beginning on June 12, 2024, and ending on June 11, 2029;

(i) The term “Misconduct Entity” means any one of the following: an entity subject to one of the Covered Convictions, *i.e.*, UBS, UBS France (recently merged into UBS Europe), CSAG and CSSEL; the entity subject to the 2013 UBS Conviction, *i.e.*, UBS Securities Japan; or an entity that was

²⁹ For purposes of the five-year exemption, references to ERISA section 406, unless otherwise specified, should be read to refer as well to the corresponding provisions of Code section 4975.

³⁰ UBS represents that UBS O’Connor LLC and UBS Realty Investors LLC are entities under the UBS corporate umbrella that currently offer investment products which are accessible by ERISA-covered plans, but do not currently rely on Class PTE 84–14 when managing those products.

the subject of the FX Misconduct, *i.e.*, UBS.

(j) The term “Related QPAM” means any current or future “qualified professional asset manager” (as defined in Section VI(a) of PTE 84–14) that relies on the relief provided by PTE 84–14, and with respect to which UBS owns a direct or indirect five (5) percent or more interest, but with respect to which a Misconduct Entity is not an “affiliate” (as defined in section VI(d)(1) of PTE 84–14). The term “Related QPAM” excludes a Misconduct Entity.

(k) The term “best knowledge,” “to the best of one’s knowledge,” “best knowledge at that time,” and other similar “best knowledge” terms shall include matters that are known to the applicable individual or should be known to such individual upon the exercise of such individual’s due diligence required under the circumstances, and, with respect to an entity other than a natural person, such term includes matters that are known to the directors and officers of the entity or should be known to such individuals upon the exercise of such individuals’ due diligence required under the circumstances.

(l) The term “UBS Seconded Employee” means, an individual nominally employed by a Misconduct Entity who performs work on behalf of a UBS QPAM; provided that such UBS QPAM is solely responsible for the management and control of the employee’s job activities performed on behalf of such QPAM. Notwithstanding the preceding sentence, the UBS QPAM must be solely responsible for the establishment of the employee’s job duties and terms of employment (including compensation, promotions, and benefits); and must have supervisory responsibility with respect to, among other things, the employee’s performance, training, and disciplinary actions.

(m) The term “UBS QPAMs” means, individually or collectively, the Affiliated QPAMs and/or the Related QPAMs.

(n) The “conduct” of any person or entity that is the “subject of” the Criminal Activity encompasses any misconduct of CSAG, CSSEL, UBS, UBS France (later merged with UBS Europe), UBS Securities Japan, and/or their personnel: (i) that is described in Exhibit 3 to the Plea Agreement entered into between UBS and the Department of Justice Criminal Division, on May 20, 2015, in connection with case number 3:15-cr-00076-RNC; (ii) that is described in Exhibits 3 and 4 to the Plea Agreement entered into between UBS Securities Japan and the Department of

Justice Criminal Division, on December 19, 2012, in connection with case number 3:12-cr-00268-RNC; (iii) that is described in Exhibit 1 of the Plea Agreement (Factual Basis for Breach) entered into between UBS and the Department of Justice Criminal Division, on May 20, 2015, in connection with Case Number 3:15-cr-00076-RNC filed in the US District Court for the District of Connecticut; (iv) that is the basis of the 2019 UBS France Conviction; and (v) that is the subject of the 2014 CSAG Conviction and the 2022 CSSEL Conviction described in Section I(c)(1) and (c)(2).

(o) The term “participate in” when used to describe an individual or entity’s participation in the Criminal Activity refers not only to active participation in the Criminal Activity but also includes an individual or entity’s knowledge or approval of the Criminal Activity, without taking active steps to prohibit such conduct, such as reporting the conduct to the individual’s supervisors, and to the Board of Directors.

Section II. Covered Transactions

If this proposed exemption is granted, the UBS QPAMs would not be precluded from relying on the exemptive relief provided by Prohibited Transaction Exemption 84–14 (PTE 84–14)³¹ during the Exemption Period, notwithstanding the “Covered Convictions,” provided that the definitions in Section I and the conditions in Section III are satisfied.

Section III. Conditions

(a) The UBS QPAMs (including their officers, directors, agents other than the Misconduct Entities, employees of such QPAMs, and UBS Seconded Employees) did not know or did not have reason to know of and did not participate in the conduct underlying the Criminal Activity. Further, any other party engaged on behalf of the UBS QPAMs who had responsibility for, or exercised authority in connection with, the management of plan assets did not know or have reason to know of and did not participate in the criminal conduct underlying the Criminal Activity.

(b) The UBS QPAMs (including their officers, directors, agents other than the Misconduct Entities, employees of such QPAMs, and UBS Seconded Employees) did not receive direct compensation, or knowingly receive indirect compensation, in connection with the

criminal conduct that is the subject of the Criminal Activity. Further, any other party engaged on behalf of the UBS QPAMs who had responsibility for, or exercised authority in connection with the management of plan assets did not receive direct compensation, or knowingly receive indirect compensation, in connection with the Criminal Activity;

(c) The Affiliated QPAMs do not currently and will not in the future employ or knowingly engage any of the individuals who participated in the criminal conduct underlying the Criminal Activity;

(d) At all times during the Exemption Period, no Affiliated QPAM will use its authority or influence to direct an “investment fund” (as defined in Section VI(b) of PTE 84–14) that is subject to ERISA or the Code and managed by such Affiliated QPAM with respect to one or more Covered Plans, to enter into any transaction with a Misconduct Entity or to engage a Misconduct Entity to provide any service to such investment fund, for a direct or indirect fee borne by such investment fund, regardless of whether such transaction or service may otherwise be within the scope of relief provided by an administrative or statutory exemption. An Affiliated QPAM will not fail this condition solely because:

(1) A UBS (or successor) affiliate serves as a local sub-custodian that is selected by an unaffiliated global custodian that, in turn, is selected by someone other than a UBS QPAM; or

(2) Services are provided by UBS Seconded Employees;

(e) Any failure of an Affiliated QPAM to satisfy Section I(g) of PTE 84–14 arose solely from the Covered Convictions;

(f) A UBS QPAM did not exercise authority over the assets of any plan subject to Part 4 of Title I of ERISA (an “ERISA-covered plan”) or Code section 4975 (an “IRA”) in a manner that it knew or should have known would further the criminal conduct underlying the Criminal Activity; or cause the UBS QPAM or its affiliates to directly or indirectly profit from the criminal conduct underlying the Criminal Activity;

(g) No Misconduct Entity will act as a fiduciary within the meaning of ERISA section 3(21)(A)(i) or (iii) or Code section 4975(e)(3)(A) and (C) with respect to ERISA-covered Plan and IRA assets, except that each may act as such a fiduciary with respect to employee benefit plans sponsored for its own employees or employees of an affiliate. No Misconduct Entity will be treated as violating the conditions of the

³¹ 49 FR 9494 (March 13, 1984), as corrected at 50 FR 41430, (Oct. 10, 1985), as amended at 70 FR 49305 (Aug. 23, 2005), as amended at 75 FR 38837 (July 6, 2010), and as amended at 89 FR 23090 (April 3, 2024).

exemption solely because it acted as an investment advice fiduciary within the meaning of ERISA section 3(21)(A)(ii) or Code section 4975(e)(3)(B);

(h)(1) Each Affiliated QPAM must maintain, adjust (to the extent necessary), implement, and follow the written policies and procedures described below (Policies).³² The Policies must require and must be reasonably designed to ensure that:

(i) The asset management decisions of the QPAM are conducted independently of the corporate and management and business activities of each Misconduct Entity, and without considering any fee a related local sub-custodian may receive from those decisions. This condition does not preclude an Affiliated QPAM, as defined in Section I(b)(1), from receiving publicly available research and other widely available information from a UBS affiliate;

(ii) The QPAM fully complies with ERISA's fiduciary duties, and with ERISA and the Code's prohibited transaction provisions, in each case as applicable with respect to each Covered Plan, and does not knowingly participate in any violation of these duties and provisions with respect to Covered Plans;

(iii) The QPAM does not knowingly participate in any other person's violation of ERISA or the Code with respect to Covered Plans;

(iv) Any filings or statements made by the QPAM to regulators, including but not limited to, the Department, the Department of the Treasury, the Department of Justice, and the Pension Benefit Guaranty Corporation, on behalf of or in relation to Covered Plans, are materially accurate and complete, to the best of such QPAM's knowledge at that time;

(v) To the best of its knowledge at that time, the QPAM does not make material misrepresentations or omit material information in its communications with such regulators with respect to Covered Plans, or make material misrepresentations or omit material information in its communications with Covered Plans; and

(vi) The QPAM complies with the terms of this five-year exemption;

(2) Any violation of, or failure to comply with an item in subparagraphs (h)(1)(ii) through (vi), is corrected as soon as reasonably possible upon discovery, or as soon after the QPAM reasonably should have known of the noncompliance (whichever is earlier),

and any such violation or compliance failure not so corrected is reported, upon the discovery of such failure to so correct, in writing. This report must be made to the head of compliance and the general counsel (or their functional equivalent) of the relevant QPAM that engaged in the violation or failure, and the independent auditor responsible for reviewing compliance with the Policies. A QPAM will not be treated as having failed to develop, implement, maintain, or follow the Policies, if it corrects any instance of noncompliance as soon as reasonably possible upon discovery, or as soon as reasonably possible after the QPAM reasonably should have known of the noncompliance (whichever is earlier), and provided that it adheres to the reporting requirements set forth in this subparagraph (2);

(3) Each Affiliated QPAM must maintain, adjust (to the extent necessary), and implement or continue a program of training during the Exemption Period (the Training) that is conducted at least annually for all relevant Affiliated QPAM asset/portfolio management, trading, legal, compliance, and internal audit personnel.³³ The Training must:

(i) At a minimum, cover the Policies, ERISA and Code compliance (including applicable fiduciary duties and the prohibited transaction provisions), ethical conduct, the consequences for not complying with the conditions of this exemption (including any loss of exemptive relief provided herein), and the requirement for prompt reporting of wrongdoing;

(ii) Be conducted by a professional who has been prudently selected and who has appropriate technical training and proficiency with ERISA and the Code to perform the tasks required by this exemption; and

(iii) Be conducted in-person, electronically, or via a website;

(i)(1) Each Affiliated QPAM submits to an audit conducted by an independent auditor, who has been prudently selected and who has appropriate technical training and proficiency with ERISA and the Code, to evaluate the adequacy of, and each Affiliated QPAM's compliance with, the Policies and Training described above in Section (h). The audit requirement must be incorporated in the Policies. The initial audit under this exemption must cover the period that begins on June 12, 2024, and ends on June 11, 2025, and the audit must be completed

by Thursday, December 11, 2025. The second audit must cover the period that begins on June 12, 2025, and ends on June 11, 2026, and must be completed by Friday, December 11, 2026. The third audit must cover the period that begins on June 12, 2026, and ends on June 11, 2027, and must be completed by Monday, December 13, 2027. The fourth audit must cover the period that begins on June 12, 2027, and ends on June 11, 2028, and must be completed by Monday, December 11, 2028. The fifth audit must cover the period that begins on June 12, 2028, and ends on June 11, 2029, and must be completed by Tuesday, December 11, 2029.

Notwithstanding the audit periods described above, the audit required under PTE 2023-14 must be completed for the prior period of June 12, 2023, through June 11, 2024 and delivered to the Department in accordance with the terms of that exemption. The prior exemption audit report(s) must be submitted in accordance with section III(i)(9) below;

(2) Within the scope of the audit and to the extent necessary for the auditor, in its sole opinion, to complete its audit and comply with the conditions for relief described herein, and only to the extent such disclosure is not prevented by state or federal statute, or involves communications subject to attorney-client privilege, each Affiliated QPAM and, if applicable, UBS, must grant the auditor unconditional access to its business, including, but not limited to: its computer systems; business records; transactional data; workplace locations; training materials; and personnel. Such access is limited to information relevant to the auditor's objectives as specified by the terms of this exemption;

(3) The auditor's engagement must specifically require the auditor to determine whether each Affiliated QPAM has developed, implemented, maintained, and followed the Policies in accordance with the conditions of this one-year exemption, and has developed and implemented the Training, as required herein;

(4) The auditor's engagement must specifically require the auditor to test each Affiliated QPAM's operational compliance with the Policies and Training. In this regard, the auditor must test, for each Affiliated QPAM, a sample of such Affiliated QPAM's transactions involving Covered Plans, sufficient in size and nature to afford the auditor a reasonable basis to determine such Affiliated QPAM's operational compliance with the Policies and Training;

(5) For the audit, on or before the end of the relevant period described in

³² This exemption does not preclude the UBS QPAMs and CS Affiliated QPAM from maintaining separate Policies provided that the Policies comply with this exemption.

³³ The exemption does not preclude an UBS QPAM from maintaining separate training programs provided each training program complies with this exemption.

Section III(i)(1) for completing the audit, the auditor must issue a written report (the Audit Report) to UBS and the Affiliated QPAM to which the audit applies that describes the procedures performed by the auditor in connection with its examination. The auditor, at its discretion, may issue a single consolidated Audit Report that covers all the Affiliated QPAMs. The Audit Report must include the auditor's specific determinations regarding:

(i) The adequacy of each Affiliated QPAM's Policies and Training; each Affiliated QPAM's compliance with the Policies and Training; the need, if any, to strengthen such Policies and Training; and any instance of the respective Affiliated QPAM's noncompliance with the written Policies and Training described in Section III(h) above. The Affiliated QPAM must promptly address any noncompliance and must promptly address or prepare a written plan of action to address any determination as to the adequacy of the Policies and Training and the auditor's recommendations (if any) with respect to strengthening the Policies and Training of the respective Affiliated QPAM. Any action taken or the plan of action to be taken by the respective Affiliated QPAM must be included in an addendum to the Audit Report (such addendum must be completed prior to the certification described in Section III(i)(7) below). In the event such a plan of action to address the auditor's recommendation regarding the adequacy of the Policies and Training is not completed by the time of submission of the Audit Report, the following period's Audit Report must state whether the plan was satisfactorily completed. Any determination by the auditor that an Affiliated QPAM has implemented, maintained, and followed sufficient Policies and Training must not be based solely or in substantial part on an absence of evidence indicating noncompliance. In this last regard, any finding that an Affiliated QPAM has complied with the requirements under this subparagraph must be based on evidence that each Affiliated QPAM has implemented, maintained, and followed the Policies and Training required by this exemption. Furthermore, the auditor must not solely rely on the Exemption Report created by the Compliance Officer, as described in Section III(m) below, as the basis for the auditor's conclusions in lieu of independent determinations and testing performed by the auditor as required by Section III(i)(3) and (4) above; and

(ii) The adequacy of the Exemption Review described in Section III(m);

(6) The auditor must notify the respective Affiliated QPAM of any instance of noncompliance identified by the auditor within five (5) business days after such noncompliance is identified by the auditor, regardless of whether the audit has been completed as of that date;

(7) With respect to the Audit Report, the General Counsel, or one of the three most senior executive officers of the Affiliated QPAM to which the Audit Report applies, must certify in writing, under penalty of perjury, that the officer has reviewed the Audit Report and this exemption; that, to the best of such officer's knowledge at the time, such Affiliated QPAM has addressed, corrected, and remedied any noncompliance and inadequacy or has an appropriate written plan to address any inadequacy regarding the Policies and Training identified in the Audit Report. Such certification must also include the signatory's determination that, to the best of such officer's knowledge at the time, the Policies and Training in effect at the time of signing are adequate to ensure compliance with the conditions of this exemption and with the applicable provisions of ERISA and the Code;

(8) The Risk Committee of UBS's Board of Directors is provided a copy of the Audit Report; and a senior executive officer of UBS's Compliance and Operational Risk Control function must review the Audit Report for each Affiliated QPAM and must certify in writing, under penalty of perjury, that such officer has reviewed the Audit Report;

(9) Each Affiliated QPAM provides its certified Audit Report, by regular mail to: Office of Exemption Determinations (OED), 200 Constitution Avenue NW, Washington, DC 20001; or via email to *e-OED@dol.gov*. This delivery must take place no later than 45 days following completion of the Audit Report. The Audit Reports will be made part of the public record regarding this five-year exemption. Furthermore, each Affiliated QPAM must make its Audit Reports unconditionally available, electronically or otherwise, for examination upon request by any duly authorized employee or representative of the Department, other relevant regulators, and any fiduciary of a Covered Plan;

(10) The auditor must provide the Department, upon request, for inspection and review, access to all the workpapers created and used in connection with the audit, provided such access and inspection is otherwise permitted by law;

(11) UBS must notify OED no later than August 12, 2024, of the auditor

selected to complete audits required by Section III(i)(1) above for the periods covering June 12, 2024, through June 11, 2029. Any engagement agreement with an auditor to perform the audit required by this exemption that is entered into subsequent to the effective date of this exemption must be submitted to OED no later than two months after the execution of such agreement;

(12) For only the initial audit required by Section III(i)(1) above for the period covering June 12, 2024, through June 11, 2025, the auditor must consult with the auditors who performed the audits required pursuant to PTE 2023–14 for the period of June 12, 2023, through June 11, 2024, unless such auditor is the same auditor selected under paragraph 11 of this subsection. UBS must notify OED if for any reason the consultation required by this paragraph 12 cannot occur and must provide an explanation for why the consultation cannot occur. Such consultation may, but need not, occur for subsequent audits;

(13) UBS must notify the Department of a change in the independent auditor no later than two months after the engagement of a substitute or subsequent auditor and must provide an explanation for the substitution or change including a description of any material disputes between the terminated auditor and UBS;

(j) As of the effective date of this five-year exemption, with respect to any arrangement, agreement, or contract between an Affiliated QPAM and a Covered Plan, the QPAM agrees and warrants to Covered Plans:

(1) To comply with ERISA and the Code, as applicable with respect to such Covered Plan; to refrain from engaging in prohibited transactions that are not otherwise exempt (and to promptly correct any prohibited transactions); and to comply with the standards of prudence and loyalty set forth in ERISA section 404 with respect to each such ERISA-covered plan and IRA to the extent that ERISA section 404 is applicable;

(2) To indemnify and hold harmless the Covered Plan for any actual losses resulting directly from the QPAM's violation of any conditions of this exemption, ERISA's fiduciary duties, as applicable, and of the prohibited transaction provisions of ERISA and the Code, as applicable; a breach of contract by the QPAM; or any claim arising out of the failure of such QPAM to qualify for the exemptive relief provided by PTE 84–14 as a result of a violation of Section I(g) of PTE 84–14, other than a Conviction covered under this exemption. The term "actual losses" includes, but is not limited to, losses

and related costs arising from unwinding transactions with third parties and from transitioning Plan assets to an alternative asset manager as well as costs associated with any exposure to excise taxes under Code section 4975 as a result of a QPAM's inability to rely upon the relief in PTE 84-14;

(3) Not to require (or otherwise cause) the Covered Plan to waive, limit, or qualify the liability of the QPAM for violating ERISA or the Code for engaging in prohibited transactions;

(4) Not to restrict the ability of the Covered Plan to terminate or withdraw from its arrangement with the QPAM, with respect to any investment in a separately-managed account or pooled fund subject to ERISA and managed by such QPAM, with the exception of reasonable restrictions, appropriately disclosed in advance, that are specifically designed to ensure equitable treatment of all investors in a pooled fund in the event such withdrawal or termination may have adverse consequences for all other investors. In connection with any such arrangement involving investments in pooled funds subject to ERISA entered into after the effective date of this exemption, the adverse consequences must relate to a lack of liquidity of the underlying assets, valuation issues, or regulatory reasons that prevent the fund from promptly redeeming an ERISA-covered plan's or IRA's investment, and such restrictions must be applicable to all such investors and be effective no longer than reasonably necessary to avoid the adverse consequences;

(5) Not to impose any fees, penalties, or charges for such termination or withdrawal with the exception of reasonable fees, appropriately disclosed in advance, that are specifically designed to prevent generally-recognized abusive investment practices or specifically designed to ensure equitable treatment of all investors in a pooled fund in the event such withdrawal or termination may have adverse consequences for all other investors, provided that such fees are applied consistently and in a like manner to all such investors;

(6) Not to include exculpatory provisions disclaiming or otherwise limiting liability of the QPAM for a violation of such agreement's terms. To the extent consistent with ERISA section 410, however, this provision does not prohibit disclaimers for liability caused by an error, misrepresentation, or misconduct of a plan fiduciary or other party hired by the plan fiduciary who is independent of UBS (and affiliates), or damages

arising from acts outside the control of the Affiliated QPAM; and

(7) Within 120 days after the effective date of this five-year exemption, each QPAM must provide a notice of its obligations under this Section III(j) to each Covered Plan. For prospective Covered Plans that enter into a written asset or investment management agreement with a QPAM on or after a date that is 120 days after the effective date of this exemption, the QPAM must agree to its obligations under this Section III(j) in an updated investment management agreement between the QPAM and such clients or other written contractual agreement. Notwithstanding the above, a QPAM will not violate the condition solely because a Covered Plan refuses to sign an updated investment management agreement. For new Covered Plans that were provided an investment management agreement prior to the effective date of this exemption, returning it within 120 days after the effective date of this exemption, and that signed investment management agreement requires amendment to meet the terms of the exemption, the QPAM may provide the new Covered Plan with amendments that need not be signed with any documents required by this subsection (j) within ten (10) business days after receipt of the signed agreement.

(k) Within 60 days after the publication date of the notice of final exemption in the **Federal Register**, each Affiliated QPAM provides notice of the proposed and final exemption as published in the **Federal Register**, along with a summary describing the facts that led to the Covered Convictions (the Summary), which has been submitted to the Department, and a prominently displayed statement (the Statement) that the Covered Convictions result in a failure to meet a condition in PTE 84-14, to each sponsor and beneficial owner of a Covered Plan that has entered into a written asset or investment management agreement with an Affiliated QPAM, or the sponsor of an investment fund in any case where an Affiliated QPAM acts as a sub-adviser to the investment fund in which such ERISA-covered plan and IRA invests. The Summary will be submitted to OED before it is distributed by each Affiliated QPAM. All prospective Covered Plan clients that enter into a written asset or investment management agreement with an Affiliated QPAM after a date that is 60 days after the effective date of this exemption must receive a copy of the notice of the exemption, the Summary, and the Statement before, or contemporaneously with, the Covered Plan's receipt of a

written asset or investment management agreement from the Affiliated QPAM. The notices may be delivered electronically (including by an email that has a link to the one-year exemption).

(l)(1) The Affiliated QPAMs must comply with each condition of PTE 84-14, as amended, with the sole exception of the violation of Section I(g) of PTE 84-14 that is attributable to the Covered Convictions. If, during the Exemption Period, an entity within UBS's corporate structure is convicted of a crime described in Section I(g) of PTE 84-14 (other than the Covered Convictions), relief in this exemption would terminate immediately.

(m)(1) Within 60 days after the date of publication of the exemption, each Affiliated QPAM must designate a senior compliance officer (the Compliance Officer) who will be responsible for compliance with the Policies and Training requirements described herein. For purposes of this condition (m), each relevant line of business within an Affiliated QPAM may designate its own Compliance Officer(s). Notwithstanding the above, the appointed Compliance Officer must not be a person who: (i) participated in the criminal conduct underlying the Criminal Activity, or knew of, or (ii) had reason to know of, the Criminal Activity without taking active documented steps to stop the misconduct;

The Compliance Officer must conduct a review of each twelve-month period of the Exemption Period (the Exemption Review), to determine the adequacy and effectiveness of the implementation of the Policies and Training.³⁴ With respect to the Compliance Officer, the following conditions must be met:

(i) The Compliance Officer must be a professional who has extensive experience with, and knowledge of, the regulation of financial services and products, including under ERISA and the Code; and

(ii) The Compliance Officer must have a direct reporting line to the highest-ranking corporate officer in charge of compliance for the applicable Affiliated QPAM.

(2) With respect to the Exemption Review, the following conditions must be met:

(i) The Annual Exemption Review includes a review of the Affiliated QPAM's compliance with and effectiveness of the Policies and Training and of the following: any

³⁴ Pursuant to PTE 2023-14, the Compliance Officer also must conduct and complete an exemption review within three months of June 11, 2024.

compliance matter related to the Policies or Training that was identified by, or reported to, the Compliance Officer or others within the compliance and risk control function (or its equivalent) during the time period; the most recent Audit Report issued pursuant to this exemption or PTE 2023–14; any material change in the relevant business activities of the Affiliated QPAMs; and any change to ERISA, the Code, or regulations related to fiduciary duties and the prohibited transaction provisions that may be applicable to the activities of the Affiliated QPAMs;

(ii) The Compliance Officer prepares a written report for the Exemption Review (an Exemption Report) that (A) summarizes their material activities during the prior year; (B) sets forth any instance of noncompliance discovered during the prior year, and any related corrective action; (C) details any change to the Policies or Training to guard against any similar instance of noncompliance occurring again; and (D) makes recommendations, as necessary, for additional training, procedures, monitoring, or additional and/or changed processes or systems, and management's actions on such recommendations;

(iii) In the Exemption Report, the Compliance Officer must certify in writing that to the best of his or her knowledge at the time: (A) the report is accurate; (B) the Policies and Training are working in a manner which is reasonably designed to ensure that the Policies and Training requirements described herein are met; (C) any known instance of noncompliance during the prior year and any related correction taken to date have been identified in the Exemption Report; and (D) the Affiliated QPAMs have complied with the Policies and Training, and/or corrected (or are correcting) any known instances of noncompliance in accordance with Section III(h) above;

(iv) The Exemption Report must be provided to appropriate corporate officers of UBS and to each Affiliated QPAM to which such report relates, and to the head of compliance and the general counsel (or their functional equivalent) of UBS, and the relevant Affiliated QPAM. The Exemption Report must be made unconditionally available to the independent auditor described in Section III(i) above;

(v) The Exemption Review, including the Compliance Officer's written Annual Exemption Report, must cover the Exemption Period, and the Annual Review, including the Compliance Officer's written Report, must be completed within three (3) months

following the end of the period to which it relates;

(n) UBS imposes its internal procedures, controls, and protocols on each Misconduct Entity to reduce the likelihood of any recurrence of conduct that is the subject of the Criminal Activity;

(o) Relief in this exemption will terminate on the date that is six months following the date that a U.S. regulatory authority makes a final decision that UBS or an affiliate of either failed to comply in all material respects with any requirement imposed by such regulatory authority in connection with the Covered Convictions;

(p) Each Affiliated QPAM will maintain records necessary to demonstrate that the conditions of this exemption have been met for six (6) years following the date of any transaction for which the Affiliated QPAM relies upon the relief in this exemption;

(q) During the Exemption Period, UBS must: (1) immediately disclose to the Department any Deferred Prosecution Agreement (a DPA) or Non-Prosecution Agreement (an NPA) with the U.S. Department of Justice, entered into by UBS or any of its affiliates (as defined in Section VI(d) of PTE 84–14) in connection with conduct described in Section I(g) of PTE 84–14 or section 411 of ERISA via email addressed to *e-OED@dol.gov*; and (2) immediately provide the Department with any information requested by the Department, as permitted by law, regarding the agreement and/or conduct and allegations that led to the agreement via email addressed to *e-OED@dol.gov*;

(r) Within 60 days after the effective date of this exemption, each Affiliated QPAM, in its agreements with, or in other written disclosures provided to Covered Plans, will clearly and prominently inform Covered Plan clients of their right to obtain a copy of the Policies or a description (Summary Policies) which accurately summarizes key components of the QPAM's written Policies developed in connection with this exemption. If the Policies are thereafter changed, each Covered Plan client must receive a new disclosure within six (6) months following the end of the calendar year during which the Policies were changed.³⁵ With respect to this requirement, the description may be continuously maintained on a website, provided that such website link to the

³⁵ If the Applicant meets this disclosure requirement through Summary Policies, changes to the Policies shall not result in the requirement for a new disclosure unless, as a result of changes to the Policies, the Summary Policies are no longer accurate.

Policies or Summary Policies is clearly and prominently disclosed to each Covered Plan;

(s) An Affiliated QPAM will not fail to meet the terms of this five-year exemption solely because a different Affiliated QPAM fails to satisfy a condition for relief described in Section III(c), (d), (h), (i), (j), (k), (m), (p), or (r); or if the independent auditor described in Section III(i) fails to comply with a provision of the exemption other than the requirement described in Section III(i)(11), provided that such failure did not result from any actions or inactions of UBS or its affiliates; and

(t) If the independent auditor or UBS or its affiliates learns of any material noncompliance with a condition of this exemption, UBS must send a notice (a "Violation Notice") to all affected Covered Plans and the Department that prominently and conspicuously states or describes: (1) UBS, or the UBS QPAM, as applicable, failed to meet the terms of this exemption (and describe the failure), (2) the extent to which UBS QPAMs have potentially been operating without an exemption due to the failure, (3) whether UBS plans to apply for retroactive relief from the Department for this failed condition; (4) any further transactions engaged in by the UBS QPAMs on behalf of Covered Plans that may be non-exempt prohibited transactions unless the Department grants retroactive relief for the period in which the transactions occurred; and (5) UBS must indemnify and hold harmless the Covered Plan for: any actual losses resulting directly from the QPAM's failure to comply with any conditions of this exemption, ERISA's fiduciary duties and of the prohibited transaction provisions of ERISA and the Code, a breach of contract by the QPAM, or any claim arising out of the failure of such QPAM to qualify for the exemptive relief provided by PTE 84–14 as a result of a violation of PTE 84–14 Section I(g), other than a Conviction covered under the exemption. The Violation Notice must be sent to all affected Covered Plans and the Department within 14 days of discovering the violation.

(u) All the material facts and representations set forth in the Summary of Facts and Representations are true and accurate at all times.

(v) Each UBS QPAM to develop written processes that clearly describe: (1) how the QPAM identifies and quantifies "actual losses" for purposes of Section III(j)(2); and (2) how Covered Plans may recover or avoid incurring the losses that the UBS QPAM must indemnify or hold Covered Plans harmless from incurring pursuant to Section III(j)(2). Each UBS QPAM must

develop these processes within 30 days after the date the Department publishes a final exemption in the **Federal Register**.

Applicability Date: This exemption will be in effect for the period beginning on June 12, 2024 and ending on June 11, 2029.

Signed at Washington, DC, this 5th day of June 2024.

George Christopher Cosby,

*Director, Office of Exemption Determinations,
Employee Benefits Security Administration,
U.S. Department of Labor.*

[FR Doc. 2024–12746 Filed 6–10–24; 8:45 am]

BILLING CODE 4510–29–P

DEPARTMENT OF LABOR

Employment and Training Administration

Work Opportunity Tax Credit (WOTC) Program

AGENCY: Employment and Training
Administration (ETA), Labor.

ACTION: Notice.

SUMMARY: This Notice announces the revised administrative formula methodology that ETA uses to distribute annual allotment funding to State grantees (53 State Workforce Agencies (SWAs)) for the purpose of administering the Work Opportunity Tax Credit (WOTC). Additionally, this Notice formally communicates the substantial changes to the administrative formula and announces the actualized State allotments for fiscal year (FY) 2024, the revised formula's implementation year, based on Congress' budgetary appropriations.

DATES: The FY 2024 allotment covers the period of October 1, 2023–September 30, 2024.

FOR FURTHER INFORMATION CONTACT:

LaToria Strickland, Office of Workforce Investment, Employment and Training Administration, U.S. Department of Labor, 200 Constitution Avenue NW, Suite C–4510, Washington, DC 20210, telephone: (202) 693–3980 (this is not a toll-free number) or by email: Ask.WOTC@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.

SUPPLEMENTARY INFORMATION:

Background: WOTC is a Federal tax credit available to eligible employers that hire and pay wages to first-time, qualifying members of WOTC targeted groups. Section 51 of the Internal Revenue Code of 1986, as amended, provides the legislative authority for the

WOTC. (See [https://uscode.house.gov/view.xhtml?req=\(title:26%20section:51%20edition:prelim\)](https://uscode.house.gov/view.xhtml?req=(title:26%20section:51%20edition:prelim))). WOTC is authorized until December 31, 2025, under division EE, title I, section 113 of the Consolidated Appropriations Act, 2021 (Pub. L. 116–260).

This Notice represents the second of a two-stage process. On February 21, 2023, ETA published a Request for Comment in which the Department proposed modifications to WOTC procedural guidance and the administrative formula (88 FR 10540), hereinafter referred to as the initial Notice. The 60-day public comment period closed on April 24, 2023. The initial Notice presented planning estimates for the modified administrative formula's implementation year, FY 2024, and the FY 2022 actualized allotments. In the initial Notice, ETA committed to publishing modifications to WOTC procedural guidance in a Change 1 to Training and Employment Guidance Letter (TEGL) No. 16–20, “*Updated Work Opportunity Tax Credit (WOTC) Procedural Guidance*,”¹ and publishing the updated administrative formula in the **Federal Register**. Based on the comments received during the public comment period and ETA's consideration of them, ETA finalized the WOTC administrative formula with updated data metrics in the formula methodology, as originally proposed in the initial Notice.

In this second stage, the finalized formula and actual FY 2024 State allotments are described further in this subsequent Notice. (The FY 2024 State allotments are also published in Change 2 to TEGL No. 06–23, “*Work Opportunity Tax Credit (WOTC) Initial Fiscal Year (FY) 2024 Funding Allotments*.”)²

This subsequent Notice contains five sections, as follows:

- *Section I* provides the historical formula methodology used for WOTC State allotments, effective FYs 1996–2023.

- *Section II* reviews the proposed administrative formula that was described in the initial Notice (88 FR 10540), published in the **Federal Register** on February 21, 2023.

¹ ETA, TEGL No. 16–20, Change 1, “*Updated Work Opportunity Tax Credit (WOTC) Procedural Guidance*,” Nov. 20, 2023, <https://www.dol.gov/agencies/eta/advisories/tegl-16-20-change-1>.

² ETA, TEGL No. 06–23, Change 2, “*Change 2 to Training and Employment Guidance Letter No. 06–23, Work Opportunity Tax Credit (WOTC) Initial Fiscal Year Allotments for Fiscal Year 2024*,” May 09 2024, <https://www.dol.gov/agencies/eta/advisories/tegl-06-23-change-2>.

- *Section III* summarizes the comments that ETA received in response to the initial Notice and ETA's decisions concerning the allotment formula modifications, based on those comments.

- *Section IV* describes the formula's “stop-loss/stop-gain” provisions, which are designed to provide a staged transition from the old to the new funding levels for State allotments. Additionally, section IV describes the minimum funding provisions for States under the modified formula. These provisions were previously discussed in detail in the initial Notice (88 FR 10540).

- *Section V* describes the application of the modified formula (using congressional budgetary appropriations) for FY 2024 allotments and subsequent years. The table appended to this Notice reflects the actual FY 2024 distribution resulting from the revised allotment formula.

I. Historical Formula Methodology

The WOTC administrative formula was developed by ETA in 1996 for the purpose of distributing Federal funds to 52 State grantees (50 United States, District of Columbia, and U.S. Virgin Islands) to administer the WOTC and the Welfare-to-Work (WtW), enacted in 1997, tax credit programs. ETA published the original formula methodology in a **Federal Register** Notice (68 FR 15745) on April 1, 2003, announcing the FY 2003 WOTC and WtW program grants to States:

“After reserving \$584,200 for postage and \$20,000 for the Virgin Islands, funds are distributed to states by administrative formula with a \$64,000 minimum allotment and a 95 percent stop-loss/120 percent stop-gain from the prior year allotment share percentage.

The allocation formula is as follows:

(1) 50 percent based on each state's relative share of total FY 2002 (the prior FY) certifications issued for the WOTC/WtW Tax Credit program;

(2) 30 percent based on each state's relative share of the civilian labor force (CLF) for calendar year 2001 (the preceding calendar year); and

(3) 20 percent based on each state's relative share of the adult recipients of Temporary Assistance for Needy Families (TANF) for FY 2001” (FY 2001 was the second preceding FY for which complete annual TANF data was available).

The WtW program, which focused on TANF recipients, was folded into WOTC in 2006 by division A, title I, section 105 of the Tax Relief and Health Care Act of 2006 (Pub. L. 109–432). While ETA has made incremental

modifications over time, including removing the set-aside for postage, increasing the minimum allotment from \$64,000 to \$66,000 (3% increase), and adding the Commonwealth of Puerto Rico as a State grantee, the WOTC administrative formula methodology has remained largely unchanged. ETA used this administrative formula recently for the FY 2023 allotments, as provided in TEGL No. 06–22, “*Work Opportunity Tax Credit (WOTC) Initial Funding Allotments for Fiscal Year 2023*,”³:

“After allocating \$20,000 to the Virgin Islands, ETA distributes the remaining funds to the SWAs by administrative formula with a \$66,000 minimum allotment and a 95 percent stop-loss/120 percent stop-gain from the previous year allotment percentage. The administrative formula is calculated as follows:

(1) 50 percent is based on each state’s relative share of total WOTC certifications issued from October 1, 2021 through September 30, 2022 (the prior fiscal year);

(2) 30 percent is based on each state’s relative share of the CLF averages for the 12-month period from October 1, 2021 through September 30, 2022 (the prior fiscal year); and

(3) 20 percent is based on each state’s relative share of adult recipients of TANF averages from October 1, 2020, through September 30, 2021 (the 12-month period from the second preceding fiscal year).”

II. Formula Updates and Modifications

The WOTC administrative formula bases 50 percent of States’ annual allotments on each State’s relative share of total WOTC certifications issued in the most recently completed FY’s available data (October 1–September 30). Thirty percent is based on each State’s relative share of CLF averages for the most recently completed FY’s available data, and 20 percent is based on each State’s relative share of adult recipients of TANF averages from the second preceding FY. The same three data metrics (certifications issued, CLF averages, and TANF averages) have been the basis of the administrative formula used to determine State allotments since 1996.

In the initial Notice (Feb 2023), ETA proposed modifications to its administrative formula to factor in the SWAs’ output workload to include denials issued and to adjust for inflation. The proposed allotment formula includes two formula factors: (1) total number of determinations

issued by the SWA (certifications and denials) for the most recently completed FY’s available data, based on SWAs’ certified performance data; and (2) each State’s relative share of CLF averages for the most recently completed FY’s available data. States report their annual certification performance data on ETA Form 9058, *Certification Workload and Characteristics of Certified Individuals*, through an existing information collection under the “Work Opportunity Tax Credit” ICR, approved under OMB Control Number 1205–0371.⁴ A description of how the data is used to calculate the State allotments using the proposed modified formula is provided below:

(1) 40 percent based on each State’s relative share of certifications issued for the most recently completed fiscal year’s available data (October 1–September 30),

(2) 40 percent based on each State’s relative share of denials issued for the most recently completed fiscal year’s available data (October 1–September 30), and

(3) 20 percent based on each State’s relative share of CLF averages for the most recently completed fiscal year’s available data (October 1–September 30).

In addition to populating the administrative formula with updated metrics, ETA proposed modifications that would raise the minimum allotment to the States and improve the formula’s accuracy in terms of estimating the true administrative workload of the SWAs. The proposed modifications were a result of ETA’s review of SWAs’ quarterly performance data, WOTC State/regional coordinators’ feedback, and inquiries received from program stakeholders.

A summary of changes under the proposed modified formula (as detailed in Section IV of the initial Notice) are provided below:

- The formula will no longer factor in States’ share of adult TANF recipient averages. With this formula modification, the administrative workload of the SWA (annual certifications and denials issued) is the primary indicator used to determine fiscal year funding.

- To align the funding formula more closely with the SWAs’ workload, ETA will lessen the formula weight of the CLF averages used in the allotment formula. States with larger population sizes (*i.e.*, California, Florida, New York, and Texas) have a larger number of

eligible employers participating in WOTC. These States process a higher volume of certification requests leading to a larger volume of the determinations issued, and consequently receive a larger relative share of the Federal funding allocation.

ETA believes that focusing on the SWAs’ workload outcomes (certifications and denials issued) is the most appropriate metric on which to base WOTC State allotments. To gradually phase in State funding allotment changes due to the updated formula, ETA will continue to use the 95 percent stop-loss/120 percent stop gain funding provisions which are currently used in WOTC allotment formula calculations. This provision is described further in Section V of this subsequent Notice.

III. Summary of Public Comments Received

Although not required by Federal statute or regulations, ETA sought public comment on the proposed administrative formula modifications in the initial **Federal Register** Notice (88 FR 10540; Feb. 21, 2023). As with all grant formulas, changing calculation metrics will result in changes to each State’s relative share of Federal funding. Two commenters [SWAs] concurred with the modified formula as announced in the initial Notice, two commenters [SWAs] proposed adjusting the weight of formula calculation metrics (*i.e.*, lessening the weight for denials issued), and one commenter [SWA] raised concern for States that may receive up to a five percent decrease in allotment during the implementation year (FY 2024). ETA considered these comments and proceeded with updating the WOTC administrative formula for State allotments as originally proposed in the initial Notice. SWAs expend resources to process a growing number of employer certification requests, regardless of the application’s outcome (certification or denial). In FY 2023, SWAs issued 3,708,081 denials, representing 48 percent of the national total workload, compared to 1,918,901 certifications, representing 25 percent of the total workload.⁵ ETA recognizes this impact and, in the initial Notice, adjusted the administrative formula to better align State funding with SWA workloads by including ‘denials issued’ at the same weight as ‘certifications issued’ in the new formula.

³ TEGL 06–22, available at <https://www.dol.gov/agencies/eta/advisories/tegl-06-22>.

⁴ ETA Form 9058, *Certification Workload and Characteristics of Certified Individuals*—ETA Form 9058 (dol.gov).

⁵ National Tax Credit Certification Reporting by Fiscal Year, available at <https://www.dol.gov/agencies/eta/wotc/performance>.

IV. Description of Stop-Loss/Stop-Gain and Minimum Funding Provisions

ETA mitigates large changes in State allotments (which may be caused by changes to formula methodology) by using the “Stop-Loss/Stop-Gain” provision, which gradually phases in State funding allotment changes due to updated formula metrics. ETA will continue to use the 95 percent stop-loss/120 percent stop-gain funding provisions in the WOTC allotment formula calculations. This approach is based on a State’s previous year allotment percentage, which is its relative share of the total formula allotments. The stop-gain provision provides that no State grantee will receive an amount that is more than 120 percent of their previous year’s allotment percentage. The stop-loss provision provides that no State grantee will receive an amount less than 95 percent of their previous year’s allotment percentage. The prior (pre-FY 2024) administrative formula was calculated with 95 percent stop-loss/120 percent stop-gain provisions, and this did not change in the modified formula for FY 2024 and subsequent years.

Under the proposed new formula, the new State allotment minimum would be raised to \$119,000 (\$36,000 for U.S. Virgin Islands), adjusted for inflation. As previously mentioned, the stop-gain provision provides that no State grantee will receive an amount that is more than 120 percent of their previous year’s allotment percentage, and using the proposed new formula, some State grantees would require over a 20 percent increase of their FY 2023 allotment percentage to reach the FY

2024 allotment minimum. To phase in the increased minimum allotment, which also impacts other States’ allotments, ETA will use the stop-gain provision to gradually increase the minimum funding allotment amount to reach the new \$119,000 minimum by FY 2026. The minimum State allotment increased to \$79,131 in FY 2024, which represents a 20 percent share increase from the prior minimum of \$66,000 in FY 2023, and it will increase by 20 percent each fiscal year, to reach the new \$119,000 minimum by FY 2026. A State grantee that would receive less than \$119,000 by application of the FY 2024 formula will, at the option of ETA, continue to receive an allotment that is proportional to the SWA’s current fiscal year allotment and anticipated administrative workload.

V. Revised WOTC Administrative Formula, Effective FY 2024 State Allotments

ETA will determine State allotments for normal WOTC operations according to the following methodology, effective with the FY 2024 State allotments:

After allocating \$36,000 to the U.S. Virgin Islands, ETA distributes the remaining funds to the SWAs by administrative formula with a \$119,000 minimum allotment and a 95 percent stop-loss/120 percent stop-gain from the previous year allotment percentage. The administrative formula is calculated as follows:

(1) 40 percent based on each State’s relative share of certifications issued for the most recently completed fiscal year’s available data (October 1–September 30);

(2) 40 percent based on each State’s relative share of denials issued for the most recently completed fiscal year’s available data (October 1–September 30); and

(3) 20 percent based on each State’s relative share of CLF averages for the 12-month period of the most recently completed fiscal year’s available data (October 1–September 30).

The State allotments set forth in the table appended to this subsequent Notice reflect the distribution resulting from the revised allotment formula described above. In FY 2023 and FY 2024, Congress appropriated \$18,485,000 in funding for State grantees (SWAs) to administer WOTC. The figures in column 1 show the actual FY 2023 formula allotments to State grantees. Column 2 shows the percentage of each States’ allotment in proportion to the total funding appropriated. Column 3 shows the actual FY 2024 formula allotments with the application of the 95 percent stop-loss/120 percent stop-gain, and \$119,000 minimum funding provisions. Column 4 shows each State’s relative share of total FY 2024 allotments and column 5 shows the percentage share difference between FY 2024 and FY 2023 State allotments. Additional information on FY 2024 funding allocations may be referenced in TEGL No 06–23, *Work Opportunity Tax Credit (WOTC) Initial Funding Allotments for Fiscal Year 2024*, available at <https://www.dol.gov/agencies/eta/advisories/tegl-06-23>.

José Javier Rodríguez,

Assistant Secretary for Employment and Training Administration, Labor.

U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WORK OPPORTUNITY TAX CREDIT (WOTC) STATE ALLOTMENT GRANTS IMPACT OF FORMULA CHANGES ON FY 2024 ALLOTMENTS TO STATES

State	FY 2023 (actual)		FY 2024 (actual)		Percentage share difference (FY 2024 vs. FY 2023)
	Allotment	Percentage share	Allotment	Percentage share	
	(1)	(2)	(3)	(4)	(5)
Total	\$18,485,000	100	\$18,485,000	100	+/-
Alabama	275,882	1.5	284,832	1.5	3.3
Alaska	66,000	0.4	79,131	0.4	20.0
Arizona	344,353	1.9	326,852	1.8	-5.0
Arkansas	129,340	0.7	155,074	0.8	20.0
California	2,463,406	13.3	2,338,208	12.7	-5.0
Colorado	299,388	1.6	284,172	1.5	-5.0
Connecticut	170,021	0.9	161,380	0.9	-5.0
Delaware	80,968	0.4	97,077	0.5	20.0
District of Columbia	66,000	0.4	79,131	0.4	20.0
Florida	996,142	5.4	945,515	5.1	-5.0
Georgia	481,902	2.6	483,737	2.6	0.5
Hawaii	83,407	0.5	100,002	0.5	20.0
Idaho	74,748	0.4	89,620	0.5	20.0
Illinois	706,132	3.8	693,500	3.8	-1.7
Indiana	273,250	1.5	259,363	1.4	-5.0
Iowa	218,776	1.2	207,657	1.1	-5.0

**U.S. DEPARTMENT OF LABOR EMPLOYMENT AND TRAINING ADMINISTRATION WORK OPPORTUNITY TAX CREDIT (WOTC)
STATE ALLOTMENT GRANTS IMPACT OF FORMULA CHANGES ON FY 2024 ALLOTMENTS TO STATES—Continued**

State	FY 2023 (actual)		FY 2024 (actual)		Percentage share difference (FY 2024 vs. FY 2023)
	Allotment	Percentage share	Allotment	Percentage share	
	(1)	(2)	(3)	(4)	(5)
Kansas	146,904	0.8	139,438	0.8	–5.0
Kentucky	353,854	1.9	335,870	1.8	–5.0
Louisiana	288,003	1.6	294,826	1.6	2.5
Maine	66,000	0.4	79,131	0.4	20.0
Maryland	398,705	2.2	378,442	2.1	–5.0
Massachusetts	380,504	2.1	361,166	2.0	–5.0
Michigan	574,630	3.1	545,425	3.0	–5.0
Minnesota	288,016	1.6	273,378	1.5	–5.0
Mississippi	207,390	1.1	196,850	1.1	–5.0
Missouri	378,621	2.1	359,378	1.9	–5.0
Montana	66,000	0.4	79,131	0.4	20.0
Nebraska	133,374	0.7	126,596	0.7	–5.0
Nevada	166,333	0.9	162,766	0.9	–2.1
New Hampshire	66,000	0.4	79,131	0.4	20.0
New Jersey	326,817	1.8	354,620	1.9	8.6
New Mexico	169,874	0.9	161,240	0.9	–5.0
New York	1,253,665	6.8	1,189,950	6.4	–5.0
North Carolina	510,810	2.8	522,119	2.8	2.3
North Dakota	66,000	0.4	79,131	0.4	20.0
Ohio	720,311	3.9	825,339	4.5	14.7
Oklahoma	260,321	1.4	247,091	1.3	–5.0
Oregon	260,465	1.4	247,227	1.3	–5.0
Pennsylvania	710,605	3.8	674,490	3.7	–5.0
Puerto Rico	81,519	0.4	97,738	0.5	20.0
Rhode Island	71,478	0.4	85,699	0.5	20.0
South Carolina	250,468	1.4	267,444	1.4	6.9
South Dakota	66,000	0.4	79,131	0.4	20.0
Tennessee	653,761	3.5	620,535	3.4	–5.0
Texas	1,310,072	7.1	1,507,945	8.2	15.2
Utah	108,459	0.6	119,000	0.6	9.8
Vermont	66,000	0.4	79,131	0.4	20.0
Virginia	414,000	2.2	392,959	2.1	–5.0
Washington	415,914	2.3	394,776	2.1	–5.0
W. Virginia	118,367	0.6	119,000	0.6	0.6
Wisconsin	320,045	1.7	308,525	1.7	–3.5
Wyoming	66,000	0.4	79,131	0.4	20.0
Total	18,465,000	100	18,449,000	100	
Virgin Islands (non-formula)	20,000	n/a	36,000	n/a	

[FR Doc. 2024–12706 Filed 6–10–24; 8:45 am]

BILLING CODE 4510–FN–P

DEPARTMENT OF LABOR**Employment and Training
Administration****Employment and Training
Administration Program Year 2024
Workforce Innovation and Opportunity
Act Section 167, National Farmworker
Jobs Program Preliminary State
Allotments****AGENCY:** Employment and Training
Administration, Labor.**ACTION:** Notice; request for comments.**SUMMARY:** This Notice announces
preliminary planning estimates for the
National Farmworker Jobs Program

(NFJP) Career Services and Training grants for Program Year (PY) 2024. This Notice also explains the allotment process that ETA will follow in the event that it does not award funds to any grantee in a particular state in the PY 2024 competition.

DATES: The PY 2024 NFJP allotments become effective for the grant period that begins July 1, 2024. Written comments on this notice are invited and must be received on June 25, 2024.

ADDRESSES: Comments are accepted via email to NFJP@dol.gov. Please enter “PY24 National Farmworker Jobs Program State Allotments Public Comment” in the subject line of the email.

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 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 obtain the notice in an alternative format, contact the Department 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:

Steven Rietzke, Chief, Division of National Programs, Tools and Technical Assistance, Office of Workforce Investment, at 202-693-3980. (This is not a toll-free number.) If you are deaf, hard of hearing, or have a speech disability, please dial 7-1-1 to access telecommunications relay services.

SUPPLEMENTARY INFORMATION: This notice is published pursuant to Section 182(d) of the Workforce Innovation and Opportunity Act, Prompt Allotment of Funds.

I. Background

The Department has announced the availability of funding for NFJP grants through the PY 2024 Funding Opportunity Announcement (FOA). In distributing funds, the Employment and Training Administration (ETA) calculates allotments for NFJP Career Services and Training grantees through an administrative formula. This notice provides preliminary planning estimates for the NFJP Career Services and Training grants. The allotments are based on the funds appropriated in the Further Consolidated Appropriations Act, 2024, Public Law 118-47 (from this point forward will be referred to as the "the Act").

PY 2024 funding levels, to use for planning purposes, are based on the full-year funding levels for this program in PY 2023 as indicated in **Federal Register** notice 88 FR 31279, May 16, 2023, pro-rated based on the availability of funding for NFJP formula grants in PY 2024. In PY 2024, Congress has provided \$90,134,000 for formula grants (of which \$90,048,000 is available for formula grants after setting aside \$86,000 for program integrity). While Congress appropriated the same amount for formula grants in PY 2023 and PY 2024, ETA is setting aside less funding in PY 2024 for program integrity. Accordingly, as noted above and explained further below, ETA is calculating state allotment amounts by pro-rating the PY 2024 allotment amounts based on the results of the PY 2023 formula and the updated availability of formula funding after set-asides in PY 2024.

In the competition for NFJP Career Services and Training grants, if the Department does not receive any competitive applications from eligible applicants for a state, the Department

does not plan to reopen the competition to seek prospective applicants to provide services in a state. In determining a course of action for a given state, the Department will follow the procedures described in the Funding Opportunity Announcement for the competition. For any state where the Department determines it will not award an NFJP grant under the PY 2024 competition, it will instead redistribute the state's funds among the grants awarded to other state service areas, distributing funds proportionally based on the NFJP allotment formula results for PY 2024.

As background, the PY 2024 appropriation also provides \$6,591,000 for migrant and seasonal farmworker housing (of which \$6,585,000 was allotted after \$6,000 was set aside for program integrity and of which not less than 70 percent shall be for permanent housing), and another \$671,000 was set aside for discretionary purposes. The Housing grant allotments are distributed as a result of a competition and are not the subject of this Notice.

This notice includes the following sections:

- Section II of this notice provides a discussion of the data used to populate the formula.
- Section III describes the prorated method for allotments for the implementation year starting in PY 2024.
- Section IV describes minimum funding provisions to address State service areas that would receive less than \$60,000.
- Section V provides preliminary state allotments for PY 2024.

II. Description of Data Files and Allotment Formula

The formula's original methodology is described in the **Federal Register** notice 64 FR 27390, May 19, 1999. In PY 2018, ETA incorporated two modifications to the allotment formula to provide more accurate estimates of each state service area's relative share of persons eligible for the program. The formula also used updated data from each of the four data files serving as the basis of the formula since 1999. The revised formula methodology is described in the **Federal Register** notice 83 FR 32151, July 11, 2018. In PY 2021, ETA incorporated two modifications to the allotment formula. These modifications are described in **Federal Register** notice 86 FR 32063, June 16, 2021. The **Federal Register**

notices are accessible at <https://www.federalregister.gov/>.

Like the PY 23 appropriation, the PY 24 appropriation includes the language expanding eligibility to farmworkers who are in families with total family incomes at or below 150 percent of the poverty line rather than the higher of the poverty line or 70 percent of the lower living standard income level. Because the PY 2024 allotments will be prorated based on the results of the PY 2023 formula, the PY 2024 allotment results continue to reflect modifications to the formula related to this expansion. ETA will subsequently revise relevant guidance regarding the definition of "low-income individual" as needed if the same expansion of eligibility is not included in subsequent appropriations.

III. Description of the Prorated Method for Allotments

The Department will use a prorated method for PY 2024 allotments. For PY 2024, each state service area will receive a prorated allotment, which is based on their PY 2023 allotment percentage, as applied to the PY 2024 formula funds available. ETA anticipates updating data and reimplementing a staged stop loss/stop gain in PY 2026. ETA will explain its approach to calculating allotments in PY 2026 in a subsequent notice at a later date.

IV. Minimum Funding Provisions

A state service area which would receive less than \$60,000 by application of the formula will, at the option of the DOL, receive no allotment or, if practical, be combined with another adjacent state service area. The Department has determined that funding below \$60,000 is insufficient for sustaining an independently administered program.

V. Program Year 2024 Preliminary State Allotments

The planning estimates set forth in the Table appended to this notice reflect the distribution resulting from the prorated methodology described above.

For purposes of illustrating the effects of using the prorated methodology, columns 2 and 3 show the state allotments for PY 2023 (which incorporated an 85 percent stop loss) and prorated method for PY 2024. The dollar difference between PY 2023 and PY 2024 allotments is shown in column 4. The percent difference is reported in column 5.

U.S. DEPARTMENT OF LABOR, EMPLOYMENT AND TRAINING ADMINISTRATION, NATIONAL FARMWORKER JOBS PROGRAM—
CAREER SERVICES AND TRAINING GRANTS
[Program year 2024 preliminary state allotments]

State	PY 2023 85% stop loss/ 150% stop gain	PY 2024 Prorated no stop loss/ stop gain	\$ Difference	% Difference
Total	\$90,032,000	\$90,048,000	\$16,000	0.02
Alabama	800,937	801,079	142	0.02
Alaska				0.00
Arizona	2,634,816	2,635,284	468	0.02
Arkansas	1,305,806	1,306,038	232	0.02
California	23,902,460	23,906,708	4,248	0.02
Colorado	1,819,486	1,819,809	323	0.02
Connecticut	548,535	548,632	97	0.02
Delaware	169,171	169,201	30	0.02
Dist of Columbia				0.00
Florida	3,266,891	3,267,472	581	0.02
Georgia	1,812,785	1,813,107	322	0.02
Hawaii	247,248	247,292	44	0.02
Idaho	2,401,585	2,402,012	427	0.02
Illinois	2,001,796	2,002,152	356	0.02
Indiana	1,345,052	1,345,291	239	0.02
Iowa	1,922,448	1,922,790	342	0.02
Kansas	1,360,695	1,360,937	242	0.02
Kentucky	864,671	864,825	154	0.02
Louisiana	856,431	856,583	152	0.02
Maine	446,523	446,602	79	0.02
Maryland	570,199	570,300	101	0.02
Massachusetts	561,137	561,237	100	0.02
Michigan	2,269,118	2,269,521	403	0.02
Minnesota	1,721,315	1,721,621	306	0.02
Mississippi	953,815	953,985	170	0.02
Missouri	1,334,410	1,334,647	237	0.02
Montana	765,413	765,549	136	0.02
Nebraska	1,364,634	1,364,877	243	0.02
Nevada	245,041	245,085	44	0.02
New Hampshire	159,717	159,745	28	0.02
New Jersey	842,456	842,606	150	0.02
New Mexico	1,168,559	1,168,767	208	0.02
New York	2,373,732	2,374,154	422	0.02
North Carolina	2,179,435	2,179,822	387	0.02
North Dakota	805,556	805,699	143	0.02
Ohio	1,572,744	1,573,024	280	0.02
Oklahoma	958,308	958,478	170	0.02
Oregon	2,415,002	2,415,431	429	0.02
Pennsylvania	1,928,391	1,928,734	343	0.02
Puerto Rico	2,112,901	2,113,276	375	0.02
Rhode Island	70,975	70,988	13	0.02
South Carolina	718,772	718,900	128	0.02
South Dakota	728,488	728,617	129	0.02
Tennessee	686,894	687,016	122	0.02
Texas	4,788,352	4,789,203	851	0.02
Utah	715,651	715,778	127	0.02
Vermont	224,029	224,069	40	0.02
Virginia	811,392	811,536	144	0.02
Washington	4,935,737	4,936,614	877	0.02
West Virginia	119,307	119,328	21	0.02
Wisconsin	1,881,174	1,881,508	334	0.02
Wyoming	342,010	342,071	61	0.02

José Javier Rodríguez,

Assistant Secretary for Employment and Training Administration, Labor.

[FR Doc. 2024–12701 Filed 6–10–24; 8:45 am]

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NATIONAL FOUNDATION ON THE ARTS AND THE HUMANITIES

National Endowment for the Humanities

Meeting of Humanities Panel

AGENCY: National Endowment for the Humanities; National Foundation on the Arts and the Humanities.

ACTION: Notice of meeting.

SUMMARY: The National Endowment for the Humanities (NEH) will hold twenty-four meetings, by video conference, of the Humanities Panel, a federal advisory committee, during July 2024. The purpose of the meetings is for panel review, discussion, evaluation, and recommendation of applications for financial assistance under the National Foundation on the Arts and the Humanities Act of 1965.

DATES: See **SUPPLEMENTARY INFORMATION** for meeting dates. The meetings will open at 8:30 a.m. and will adjourn by 5:00 p.m. on the dates specified below.

FOR FURTHER INFORMATION CONTACT:

Elizabeth Voyatzis, Committee Management Officer, 400 7th Street SW, Room 4060, Washington, DC 20506; (202) 606–8322; evoyatzis@neh.gov.

SUPPLEMENTARY INFORMATION: Pursuant to section 10(a)(2) of the Federal Advisory Committee Act (5 U.S.C. 10), notice is hereby given of the following meetings:

1. Date: July 16, 2024

This video meeting will discuss applications on the topics of American Literature, Language, and Studies, for the Awards for Faculty grant program, submitted to the Division of Research Programs.

2. Date: July 16, 2024

This video meeting will discuss applications on the topics of Arts, Media, and Communications, for the Awards for Faculty grant program, submitted to the Division of Research Programs.

3. Date: July 22, 2024

This video meeting will discuss applications on the topics of American History and Studies, for the Awards for Faculty grant program, submitted to the Division of Research Programs.

4. Date: July 23, 2024

This video meeting will discuss applications for the Cultural and Community Resilience grant program, submitted to the Division of Preservation and Access.

5. Date: July 23, 2024

This video meeting will discuss applications on the topics of World History and Studies, for the Awards for Faculty grant program, submitted to the Division of Research Programs.

6. Date: July 23, 2024

This video meeting will discuss applications on the topics of Literature, Medieval, and Renaissance Studies, for the Awards for Faculty grant program, submitted to the Division of Research Programs.

7. Date: July 24, 2024

This video meeting will discuss applications on the topic of Social Sciences, for the Awards for Faculty grant program, submitted to the Division of Research Programs.

8. Date: July 24, 2024

This video meeting will discuss applications on the topics of Philosophy, Politics, and History, for the Awards for Faculty grant program, submitted to the Division of Research Programs.

9. Date: July 24, 2024

This video meeting will discuss applications on the topics of Collections Care and Preservation Training, for the Preservation and Access Education and Training grant program, submitted to the Division of Preservation and Access.

10. Date: July 24, 2024

This video meeting will discuss applications for the Cultural and Community Resilience grant program, submitted to the Division of Preservation and Access.

11. Date: July 25, 2024

This video meeting will discuss applications for the Cultural and Community Resilience grant program, submitted to the Division of Preservation and Access.

12. Date: July 25, 2024

This video meeting will discuss applications for the Fellowships for Advanced Social Science Research on Japan grant program, submitted to the Division of Research Programs.

13. Date: July 25, 2024

This video meeting will discuss applications on the topics of American

Literature, Communications, and Rhetoric, for the Fellowships grant program, submitted to the Division of Research Programs.

14. Date: July 25, 2024

This video meeting will discuss applications on the topics of Music, Dance, Theater, and Performance Studies, for the Fellowships grant program, submitted to the Division of Research Programs.

15. Date: July 26, 2024

This video meeting will discuss applications on the topics of Literature and Literary Theory, for the Fellowships grant program, submitted to the Division of Research Programs.

16. Date: July 26, 2024

This video meeting will discuss applications on the topics of Religious Studies and U.S. History, for the Fellowships grant program, submitted to the Division of Research Programs.

17. Date: July 29, 2024

This video meeting will discuss applications on the topics of Africa, the Middle East, and the Ancient World, for the Fellowships grant program, submitted to the Division of Research Programs.

18. Date: July 29, 2024

This video meeting will discuss applications on the topic of European Studies, for the Fellowships grant program, submitted to the Division of Research Programs.

19. Date: July 30, 2024

This video meeting will discuss applications on the topics of Art, Architecture, and Visual Culture, for the Fellowships grant program, submitted to the Division of Research Programs.

20. Date: July 30, 2024

This video meeting will discuss applications on the topic of Philosophy, for the Fellowships grant program, submitted to the Division of Research Programs.

21. Date: July 30, 2024

This video meeting will discuss applications for the Cultural and Community Resilience grant program, submitted to the Division of Preservation and Access.

22. Date: July 31, 2024

This video meeting will discuss applications for the Cultural and Community Resilience grant program, submitted to the Division of Preservation and Access.

23. Date: July 31, 2024

This video meeting will discuss applications on the topics of Latin American, Caribbean, and American History and Studies, for the Fellowships grant program, submitted to the Division of Research Programs.

24. Date: July 31, 2024

This video meeting will discuss applications on the topics of History of Science, Health Humanities, and Social Sciences, for the Fellowships grant program, submitted to the Division of Research Programs.

Because these meetings will include review of personal and/or proprietary financial and commercial information given in confidence to the agency by grant applicants, the meetings will be closed to the public pursuant to sections 552b(c)(4) and 552b(c)(6) of Title 5, U.S.C., as amended. I have made this determination pursuant to the authority granted me by the Chair's Delegation of Authority to Close Advisory Committee Meetings dated April 15, 2016.

Dated: June 6, 2024.

Jessica Graves,

Paralegal Specialist, National Endowment for the Humanities.

[FR Doc. 2024-12772 Filed 6-10-24; 8:45 am]

BILLING CODE 7536-01-P

NUCLEAR REGULATORY COMMISSION

[NRC-2024-0108]

Monthly Notice; Applications and Amendments to Facility Operating Licenses and Combined Licenses Involving No Significant Hazards Considerations

AGENCY: Nuclear Regulatory Commission.

ACTION: Monthly notice.

SUMMARY: Pursuant to section 189a.(2) of the Atomic Energy Act of 1954, as amended (the Act), the U.S. Nuclear Regulatory Commission (NRC) is publishing this regular monthly notice. The Act requires the Commission to publish notice of any amendments issued, or proposed to be issued, and grants the Commission the authority to issue and make immediately effective any amendment to an operating license or combined license, as applicable, upon a determination by the Commission that such amendment involves no significant hazards consideration (NSHC), notwithstanding the pendency before the Commission of a request for a hearing from any person.

DATES: Comments must be filed by July 11, 2024. A request for a hearing or petitions for leave to intervene must be filed by August 12, 2024. The last monthly notice was published on May 14, 2024.

ADDRESSES: You may submit comments by any of the following; however, the NRC encourages electronic comment submission through the Federal rulemaking website.

- *Federal rulemaking website:* Go to <https://www.regulations.gov> and search for Docket ID NRC-2024-0108. 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.

- *Mail comments to:* Office of Administration, Mail Stop: TWFN-7-A60M, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, ATTN: Program Management, Announcements and Editing Staff.

For additional direction on obtaining information and submitting comments, see "Obtaining Information and Submitting Comments" in the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT:

Shirley Rohrer, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, telephone: 301-415-5411; email: Shirley.Rohrer@nrc.gov.

SUPPLEMENTARY INFORMATION:

I. Obtaining Information and Submitting Comments

A. Obtaining Information

Please refer to Docket ID NRC-2024-0108, facility name, unit number(s), docket number(s), application date, and subject when contacting the NRC about the availability of information for this action. You may obtain publicly available information related to this action by any of the following methods:

- *Federal Rulemaking Website:* Go to <https://www.regulations.gov> and search for Docket ID NRC-2024-0108.
- *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. The ADAMS

accession number for each document referenced (if it is available in ADAMS) is provided the first time that it is mentioned in this document.

- *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.

B. Submitting Comments

The NRC encourages electronic comment submission through the Federal rulemaking website (<https://www.regulations.gov>). Please include Docket ID NRC-2024-0108, facility name, unit number(s), docket number(s), application date, and subject, in your comment submission.

The NRC cautions you not to include identifying or contact information that you do not want to be publicly disclosed in your comment submission. The NRC will post all comment submissions at <https://www.regulations.gov> as well as enter the comment submissions into ADAMS. The NRC does not routinely edit comment submissions to remove identifying or contact information.

If you are requesting or aggregating comments from other persons for submission to the NRC, then you should inform those persons not to include identifying or contact information that they do not want to be publicly disclosed in their comment submission. Your request should state that the NRC does not routinely edit comment submissions to remove such information before making the comment submissions available to the public or entering the comment into ADAMS.

II. Notice of Consideration of Issuance of Amendments to Facility Operating Licenses and Combined Licenses and Proposed No Significant Hazards Consideration Determination

For the facility-specific amendment requests shown in this notice, the Commission finds that the licensees' analyses provided, consistent with section 50.91 of title 10 of the *Code of Federal Regulations* (10 CFR) "Notice for public comment; State consultation," are sufficient to support the proposed determinations that these amendment requests involve NSHC. Under the Commission's regulations in 10 CFR 50.92, operation of the facilities in accordance with the proposed amendments would not (1) involve a significant increase in the probability or

consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety.

The Commission is seeking public comments on these proposed determinations. Any comments received within 30 days after the date of publication of this notice will be considered in making any final determinations.

Normally, the Commission will not issue the amendments until the expiration of 60 days after the date of publication of this notice. The Commission may issue any of these license amendments before expiration of the 60-day period provided that its final determination is that the amendment involves NSHC. In addition, the Commission may issue any of these amendments prior to the expiration of the 30-day comment period if circumstances change during the 30-day comment period such that failure to act in a timely way would result, for example in derating or shutdown of the facility. If the Commission takes action on any of these amendments prior to the expiration of either the comment period or the notice period, it will publish in the **Federal Register** a notice of issuance. If the Commission makes a final NSHC determination for any of these amendments, any hearing will take place after issuance. The Commission expects that the need to take action on any amendment before 60 days have elapsed will occur very infrequently.

A. Opportunity To Request a Hearing and Petition for Leave To Intervene

Within 60 days after the date of publication of this notice, any person (petitioner) whose interest may be affected by any of these actions may file a request for a hearing and petition for leave to intervene (petition) with respect to that action. Petitions shall be filed in accordance with the Commission's "Agency Rules of Practice and Procedure" in 10 CFR part 2. Interested persons should consult a current copy of 10 CFR 2.309. If a petition is filed, the Commission or a presiding officer will rule on the petition and, if appropriate, a notice of a hearing will be issued.

Petitions must be filed no later than 60 days from the date of publication of this notice in accordance with the filing instructions in the "Electronic Submissions (E-Filing)" section of this document. Petitions and motions for leave to file new or amended contentions that are filed after the deadline will not be entertained absent

a determination by the presiding officer that the filing demonstrates good cause by satisfying the three factors in 10 CFR 2.309(c)(1)(i) through (iii).

If a hearing is requested, and the Commission has not made a final determination on the issue of no significant hazards consideration, the Commission will make a final determination on the issue of no significant hazards consideration, which will serve to establish when the hearing is held. If the final determination is that the amendment request involves no significant hazards consideration, the Commission may issue the amendment and make it immediately effective, notwithstanding the request for a hearing. Any hearing would take place after issuance of the amendment. If the final determination is that the amendment request involves a significant hazards consideration, then any hearing held would take place before the issuance of the amendment unless the Commission finds an imminent danger to the health or safety of the public, in which case it will issue an appropriate order or rule under 10 CFR part 2.

A State, local governmental body, federally recognized Indian Tribe, or designated agency thereof, may submit a petition to the Commission to participate as a party under 10 CFR 2.309(h) no later than 60 days from the date of publication of this notice. Alternatively, a State, local governmental body, federally recognized Indian Tribe, or agency thereof may participate as a non-party under 10 CFR 2.315(c).

For information about filing a petition and about participation by a person not a party under 10 CFR 2.315, see ADAMS Accession No. ML20340A053 (<https://adamswebsearch2.nrc.gov/webSearch2/main.jsp?AccessionNumber=ML20340A053>) and on the NRC's public website at <https://www.nrc.gov/about-nrc/regulatory/adjudicatory/hearing.html#participate>.

B. Electronic Submissions (E-Filing)

All documents filed in NRC adjudicatory proceedings, including documents filed by an interested State, local governmental body, federally recognized Indian Tribe, or designated agency thereof that requests to participate under 10 CFR 2.315(c), must be filed in accordance with 10 CFR 2.302. The E-Filing process requires participants to submit and serve all adjudicatory documents over the internet, or in some cases, to mail copies on electronic storage media, unless an exemption permitting an alternative filing method, as further discussed, is

granted. Detailed guidance on electronic submissions is located in the "Guidance for Electronic Submissions to the NRC" (ADAMS Accession No. ML13031A056) and on the NRC's public website at <https://www.nrc.gov/site-help/e-submittals.html>.

To comply with the procedural requirements of E-Filing, at least 10 days prior to the filing deadline, the participant should contact the Office of the Secretary by email at Hearing.Docket@nrc.gov, or by telephone at 301-415-1677, to (1) request a digital identification (ID) certificate, which allows the participant (or its counsel or representative) to digitally sign submissions and access the E-Filing system for any proceeding in which it is participating; and (2) advise the Secretary that the participant will be submitting a petition or other adjudicatory document (even in instances in which the participant, or its counsel or representative, already holds an NRC-issued digital ID certificate). Based upon this information, the Secretary will establish an electronic docket for the proceeding if the Secretary has not already established an electronic docket.

Information about applying for a digital ID certificate is available on the NRC's public website at <https://www.nrc.gov/site-help/e-submittals/getting-started.html>. After a digital ID certificate is obtained and a docket created, the participant must submit adjudicatory documents in Portable Document Format. Guidance on submissions is available on the NRC's public website at <https://www.nrc.gov/site-help/electronic-sub-ref-mat.html>. A filing is considered complete at the time the document is submitted through the NRC's E-Filing system. To be timely, an electronic filing must be submitted to the E-Filing system no later than 11:59 p.m. ET on the due date. Upon receipt of a transmission, the E-Filing system time-stamps the document and sends the submitter an email confirming receipt of the document. The E-Filing system also distributes an email that provides access to the document to the NRC's Office of the General Counsel and any others who have advised the Office of the Secretary that they wish to participate in the proceeding, so that the filer need not serve the document on those participants separately. Therefore, applicants and other participants (or their counsel or representative) must apply for and receive a digital ID certificate before adjudicatory documents are filed to obtain access to the documents via the E-Filing system.

A person filing electronically using the NRC's adjudicatory E-Filing system

may seek assistance by contacting the NRC's Electronic Filing Help Desk through the "Contact Us" link located on the NRC's public website at <https://www.nrc.gov/site-help/e-submittals.html>, by email to MSHD.Resource@nrc.gov, or by a toll-free call at 1-866-672-7640. The NRC Electronic Filing Help Desk is available between 9 a.m. and 6 p.m., ET, Monday through Friday, except Federal holidays.

Participants who believe that they have good cause for not submitting documents electronically must file an exemption request, in accordance with 10 CFR 2.302(g), with their initial paper filing stating why there is good cause for not filing electronically and requesting authorization to continue to submit documents in paper format. Such filings must be submitted in accordance with 10 CFR 2.302(b)–(d). Participants filing adjudicatory documents in this manner are responsible for serving their documents on all other participants.

Participants granted an exemption under 10 CFR 2.302(g)(2) must still meet the electronic formatting requirement in 10 CFR 2.302(g)(1), unless the participant also seeks and is granted an exemption from 10 CFR 2.302(g)(1).

Documents submitted in adjudicatory proceedings will appear in the NRC's electronic hearing docket, which is publicly available at <https://adams.nrc.gov/ehd>, unless excluded pursuant to an order of the presiding officer. If you do not have an NRC-issued digital ID certificate as previously described, click "cancel" when the link requests certificates and you will be automatically directed to the NRC's electronic hearing docket where you will be able to access any publicly available documents in a particular hearing docket. Participants are requested not to include personal privacy information such as social security numbers, home addresses, or personal phone numbers in their filings

unless an NRC regulation or other law requires submission of such information. With respect to copyrighted works, except for limited excerpts that serve the purpose of the adjudicatory filings and would constitute a Fair Use application, participants should not include copyrighted materials in their submission.

The following table provides the plant name, docket number, date of application, ADAMS accession number, and location in the application of the licensees' proposed NSHC determinations. For further details with respect to these license amendment applications, see the applications for amendment, which are available for public inspection in ADAMS. For additional direction on accessing information related to this document, see the "Obtaining Information and Submitting Comments" section of this document.

LICENSE AMENDMENT REQUESTS

Constellation Energy Generation, LLC.; Braidwood Station, Units 1 and 2, Will County, IL; Constellation Energy Generation, LLC.; Byron Station, Unit Nos. 1 and 2, Ogle County, IL; Constellation Energy Generation, LLC.; Calvert Cliffs Nuclear Power Plant, Units 1 and 2; Calvert County, MD; Constellation Energy Generation, LLC.; Clinton Power Station, Unit 1; Constellation FitzPatrick, LLC and Constellation Energy Generation, LLC.; James A. FitzPatrick Nuclear Power Plant; Oswego County, NY; Constellation Energy Generation, LLC.; LaSalle County Station, Units 1 and 2, LaSalle County, IL; Constellation Energy Generation, LLC.; Limerick Generating Station, Units 1 and 2; Montgomery County, PA.; Constellation Energy Generation, LLC.; Nine Mile Point Nuclear Station, Units 1 and 2; Oswego County, NY; Constellation Energy Generation, LLC.; Peach Bottom Atomic Power Station, Units 2 and 3; York and Lancaster Counties, PA; Constellation Energy Generation, LLC.; R.E. Ginna Nuclear Power Plant; Wayne County, NY

Docket No(s)	50–456, 50–457, 50–454, 50–455, 50–317, 50–318, 50–461, 50–333, 50–373, 50–374, 50–352, 50–353, 50–220, 50–410, 50–277, 50–278, 50–244.
Application date	April 12, 2024.
ADAMS Accession No	ML24103A204.
Location in Application of NSHC	Pages 2–4 of Attachment 1.
Brief Description of Amendment(s)	The proposed amendments would adopt Technical Specifications Task Force (TSTF) Traveler, TSTF–591–A, Revision 0, "Revise Risk Informed Completion Time (RICT) Program." TSTF–591–A would revise Technical Specification (TS), Section 5.5 "Programs and Manuals," "Risk Informed Completion Time Program," to reference Regulatory Guide 1.200, Revision 3, instead of Revision 2, and adds a new report to TS, Section 5.6, "Reporting Requirements," that informs the NRC of newly developed methods used to calculate a RICT. Additionally, the licensee is requesting the removal of certain stations' facility operating license condition sections associated with the implementation of the 10 CFR 50.69 and RICT programs.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Jason Zorn, Associate General Counsel, Constellation Energy Generation, 101 Constitution Ave. NW, Suite 400 East, Washington, DC 20001.
NRC Project Manager, Telephone Number	Scott Wall, 301–415–2855.

Dominion Energy Nuclear Connecticut, Inc.; Millstone Power Station, Unit No. 3; New London County, CT

Docket No(s)	50–423.
Application date	March 22, 2024.
ADAMS Accession No	ML24086A476.
Location in Application of NSHC	Page 2 of Attachment 1.
Brief Description of Amendment(s)	The proposed amendment would extend the reactor coolant pump (RCP) motor flywheel examination frequency from the currently approved 10-year inspection interval, to an interval not to exceed 20 years, consistent with Industry/Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF–421, "Revision to RCP Flywheel Inspection Program (WCAP–15666)." The availability of this technical specification improvement was announced in the Federal Register on October 22, 2003 (68 FR 60422), as part of the consolidated line-item improvement process. The licensee incorporated the original notice by reference in their license amendment request as it concluded that the proposed no significant hazards consideration determination as published on June 24, 2003 (68 FR 37590) is applicable to Millstone, Unit No. 3.

LICENSE AMENDMENT REQUESTS—Continued

Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	W.S. Blair, Senior Counsel, Dominion Energy Services, Inc., 120 Tredegar St., RS-2, Richmond, VA 23219.
NRC Project Manager, Telephone Number	Richard Guzman, 301-415-1030.
Duke Energy Progress, LLC.; Shearon Harris Nuclear Power Plant, Unit 1; Wake and Chatham Counties, NC	
Docket No(s)	50-400.
Application date	March 20, 2024.
ADAMS Accession No	ML24080A449.
Location in Application of NSHC	Page 2 of Enclosure 1.
Brief Description of Amendment(s)	The proposed amendment would extend the completion time from 1 hour to 24 hours for applicable actions of Technical Specification (TS) 3.5.1, "Accumulators." The change is consistent with NRC-approved Industry/Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler TSTF-370, "Risk-Informed Evaluation of an Extension to Accumulator Completion Times for Westinghouse Plants" (ML003771348). The availability of this TS improvement was announced in the Federal Register on March 12, 2003 (68 FR 11880), as part of the consolidated line-item improvement process.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Tracey Mitchell LeRoy, Deputy General Counsel, Duke Energy Corporation, 4720 Piedmont Row Dr., Charlotte, NC 28210.
NRC Project Manager, Telephone Number	Michael Mahoney, 301-415-3867.
Energy Northwest; Columbia Generating Station; Benton County, WA	
Docket No(s)	50-397.
Application date	January 30, 2024, as supplemented by letter dated March 20, 2024.
ADAMS Accession No	ML24030A844, ML24081A193.
Location in Application of NSHC	Pages 44-46 of Enclosure 1.
Brief Description of Amendment(s)	The proposed amendment would revise the Columbia Emergency Plan to reflect the updates contained in NUREG-0654/FEMA-REP-1, Revision 2, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," dated December 2019 (ML19347D139).
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Ryan Lukson, Assistant General Counsel, Energy Northwest, MD 1020, P.O. Box 968, Richland, WA 99352.
NRC Project Manager, Telephone Number	Mahesh Chawla, 301-415-8371.
Entergy Operations, Inc.; Arkansas Nuclear One, Unit 2; Pope County, AR	
Docket No(s)	50-368.
Application date	April 4, 2024.
ADAMS Accession No	ML24095A063.
Location in Application of NSHC	Pages 3-4 of the Enclosure.
Brief Description of Amendment(s)	The proposed amendment would correct typographical errors in the Arkansas Nuclear One, Unit 2 Technical Specifications.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Susan Raimo, Associate General Counsel—Nuclear, 101 Constitution Avenue NW, Washington, DC 20001.
NRC Project Manager, Telephone Number	Thomas Wengert, 301-415-4037.
Indiana Michigan Power Company; Donald C. Cook Nuclear Plant, Units 1 and 2; Berrien County, MI	
Docket No(s)	50-315, 50-316.
Application date	April 3, 2024, as supplemented by letter dated May 16, 2024.
ADAMS Accession No	ML24094A288, ML24137A221.
Location in Application of NSHC	Pages 24-26 of Enclosure 2.
Brief Description of Amendment(s)	The proposed amendments would revise Technical Specification (TS) 3.8.1, "AC [Alternating Current] Sources—Operating," by adding a footnote for TS 3.8.1, Required Action A.3 that would allow a one-time completion time extension from 72 hours to 288 hours to support the replacement of the 12AB (Train B) loop feed enclosure and associated bus for the Train B reserve feed preferred power source.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Robert B. Haemer, Senior Nuclear Counsel, Indiana Michigan Power Company, One Cook Place, Bridgman, MI 49106.
NRC Project Manager, Telephone Number	Scott Wall, 301-415-2855.
Southern Nuclear Operating Company, Inc.; Edwin I. Hatch Nuclear Plant, Units 1 and 2; Appling County, GA; Southern Nuclear Operating Company, Inc.; Joseph M. Farley Nuclear Plant, Units 1 and 2; Houston County, AL	
Docket No(s)	50-348, 50-364, 50-321, 50-366.
Application date	May 3, 2024.
ADAMS Accession No	ML24124A133.
Location in Application of NSHC	Pages E-22 and E-23 of the Enclosure.

LICENSE AMENDMENT REQUESTS—Continued

Brief Description of Amendment(s)	The proposed amendments would revise Technical Specification (TS) 1.1, "Use and Application Definitions," and add a new "Online Monitoring Program" to TS 5.5, "Programs and Manuals." The proposed amendments would use an online monitoring (OLM) methodology as the technical basis to switch from time-based surveillance frequency for channel calibrations to a condition-based calibration frequency based on OLM results. The proposed amendments are based on the NRC-approved topical report AMS-TR-0720R2-A, "Online Monitoring Technology to Extend Calibration Intervals of Nuclear Plant Pressure Transmitters."
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Millicent Ronnlund, Vice President and General Counsel, Southern Nuclear Operating Co., Inc., P.O. Box 1295, Birmingham, AL 35201-1295.
NRC Project Manager, Telephone Number	Jack Minzer Bryant, 301-415-0610.
Tennessee Valley Authority; Browns Ferry Nuclear Plant, Units 1, 2, and 3; Limestone County, AL; Tennessee Valley Authority; Sequoyah Nuclear Plant, Units 1 and 2; Hamilton County, TN; Tennessee Valley Authority; Watts Bar Nuclear Plant, Units 1 and 2; Rhea County, TN	
Docket No(s)	50-259, 50-260, 50-296, 50-327, 50-328, 50-390, 50-391.
Application date	April 1, 2024.
ADAMS Accession No	ML24093A047.
Location in Application of NSHC	Pages E2-4-E2-5 of Enclosure 2.
Brief Description of Amendment(s)	The proposed amendments would revise Browns Ferry Nuclear Plant, Units 1, 2, and 3, and Sequoyah Nuclear Plant, Units 1 and 2, Technical Specification (TS) 5.4.1 and Watts Bar Nuclear Plant, Units 1 and 2, TS 5.7.1 to remove the revision number for Regulatory Guide 1.33 and replace it with a reference to the revision that is specified in the TVA Nuclear Quality Assurance Plan.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	David Fountain, Executive VP and General Counsel, Tennessee Valley Authority, 6A West Tower, 400 West Summit Hill Drive, Knoxville, TN 37902.
NRC Project Manager, Telephone Number	Kimberly Green, 301-415-1627.
Virginia Electric and Power Company; Surry Power Station, Unit Nos. 1 and 2; Surry County, VA	
Docket No(s)	50-280, 50-281.
Application date	March 22, 2024.
ADAMS Accession No	ML24087A208.
Location in Application of NSHC	Pages 10-12 of Attachment 1.
Brief Description of Amendment(s)	The proposed amendments would revise the Surry Power Station, Unit Nos. 1 and 2, Technical Specification (TS), Section 3.8, Containment, to: (1) change the TS 3.8.D heading from Internal Pressure to Containment Pressure, (2) add a minimum containment air partial pressure limit to the Limiting Condition for Operation (LCO) in TS 3.8.D, and (3) add a new TS 3.8.E, Containment Air Temperature, to provide an LCO for containment average air temperature. The proposed change also revises TS 4.1, Operational Safety Review, to incorporate TS Surveillance Requirements for containment air partial pressure and containment average air temperature.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	W.S. Blair, Senior Counsel, Dominion Energy Services, Inc., 120 Tredegar St., RS-2, Richmond, VA 23219.
NRC Project Manager, Telephone Number	John Klos, 301-415-5136.

III. Notice of Issuance of Amendments to Facility Operating Licenses and Combined Licenses

During the period since publication of the last monthly notice, the Commission has issued the following amendments. The Commission has determined for each of these amendments that the application complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR chapter I, which are set forth in the license amendment.

A notice of consideration of issuance of amendment to facility operating license or combined license, as

applicable, proposed NSHC determination, and opportunity for a hearing in connection with these actions, were published in the **Federal Register** as indicated in the safety evaluation for each amendment.

Unless otherwise indicated, the Commission has determined that these amendments satisfy the criteria for categorical exclusion in accordance with 10 CFR 51.22. Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared for these amendments. If the Commission has prepared an environmental assessment under the special circumstances provision in 10 CFR 51.22(b) and has made a determination based on that

assessment, it is so indicated in the safety evaluation for the amendment.

For further details with respect to each action, see the amendment and associated documents such as the Commission's letter and safety evaluation, which may be obtained using the ADAMS accession numbers indicated in the following table. The safety evaluation will provide the ADAMS accession numbers for the application for amendment and the **Federal Register** citation for any environmental assessment. All of these items can be accessed as described in the "Obtaining Information and Submitting Comments" section of this document.

LICENSE AMENDMENT ISSUANCE(S)

Constellation Energy Generation, LLC.; Clinton Power Station, Unit No. 1; DeWitt County, IL; Constellation Energy Generation, LLC.; Dresden Nuclear Power Station, Units 2 and 3; Grundy County, IL; Constellation Energy Generation, LLC.; LaSalle County Station, Units 1 and 2; LaSalle County, IL; Constellation Energy Generation, LLC.; Quad Cities Nuclear Power Station, Units 1 and 2; Rock Island County, IL; Nine Mile Point Nuclear Station, LLC. and Constellation Energy Generation, LLC.; Nine Mile Point Nuclear Station, Unit 2; Oswego County, NY

Docket No(s)	50–461, 50–237, 50–249, 50–373, 50–374, 50–410, 50–254, 50–265.
Amendment Date	May 23, 2024.
ADAMS Accession No	ML24079A076.
Amendment No(s)	Clinton 253; Dresden 284 (U2) and 277 (U3); LaSalle 263 (U1 and 248 (U2); NMP 196 (U2); Quad Cities 300 (U1) and 296 (U2).
Brief Description of Amendment(s)	The amendments revised the technical specifications for each facility in accordance with Technical Specifications Task Force (TSTF) Traveler TSTF–264, Revision 0, “3.3.9 and 3.3.10—Delete Flux Monitors Specific Overlap Requirement SRs [Surveillance Requirements].” Specifically, the proposed changes delete SRs which verify the overlap between the source range monitor and the intermediate range monitor, and between the intermediate range monitor and the average power range monitor.
Public Comments Received as to Proposed NSHC (Yes/No).	No.

Dominion Energy Nuclear Connecticut, Inc.; Millstone Power Station, Unit No. 3; New London County, CT

Docket No(s)	50–423.
Amendment Date	May 21, 2024.
ADAMS Accession No	ML24109A003.
Amendment No(s)	289.
Brief Description of Amendment(s)	The amendment revised Technical Specification (TS) 6.9.1.6.b to support the transition to Framatome (FRM) GAIA fuel with M5™ cladding at Millstone Power Station, Unit No. 3, and the resulting application of the FRM Small Break and Realistic Large Break Loss-of-Coolant Accident (LOCA) methodologies and the associated use of the GALILEO fuel performance code within the LOCA methods. Specifically, FRM Topical Reports EMF–2328–P–A, “PWR [pressurized water reactor] Small Break LOCA Evaluation Model, S–RELAP5 Based,” EMF–2103–P–A, “Realistic Large Break LOCA Methodology for Pressurized Water Reactors,” and ANP–10349–P–A, “GALILEO Implementation in LOCA Methods,” were added to the list of methodologies for establishing core operating limits. The revision to TS 6.9.1.6.b also deleted one methodology no longer used to define core operating limits at Millstone Power Station, Unit No. 3.
Public Comments Received as to Proposed NSHC (Yes/No).	No.

DTE Electric Company; Fermi, Unit 2; Monroe County, MI

Docket No(s)	50–341.
Amendment Date	April 30, 2024.
ADAMS Accession No	ML24052A277.
Amendment No(s)	229.
Brief Description of Amendment(s)	The amendment modified Fermi 2 Technical Specification 3.8.1, “AC [Alternating Current] Sources-Operating,” to revise Surveillance Requirement 3.8.1.12, by adding a requirement to verify the crankcase overpressure automatic trip for each emergency diesel generator is bypassed on an actual or simulated emergency start signal.
Public Comments Received as to Proposed NSHC (Yes/No).	No.

Entergy Louisiana, LLC., and Entergy Operations, Inc.; River Bend Station, Unit 1; West Feliciana Parish, LA

Docket No(s)	50–458.
Amendment Date	May 16, 2024.
ADAMS Accession No	ML24081A007.
Amendment No(s)	213.
Brief Description of Amendment(s)	The amendment modified the River Bend Station, Unit 1 technical specification requirements to permit the use of Risk-Informed Completion Times in accordance with Technical Specifications Task Force (TSTF) Traveler TSTF–505, Revision 2, “Provide Risk-Informed Extended Completion Times—RITSTF [Risk-Informed TSTF] Initiative 4b.” The NRC staff issued a final model safety evaluation approving TSTF–505, Revision 2, on November 21, 2018.
Public Comments Received as to Proposed NSHC (Yes/No).	No.

Entergy Louisiana, LLC, and Entergy Operations, Inc.; River Bend Station, Unit 1; West Feliciana Parish, LA

Docket No(s)	50–458.
Amendment Date	May 16, 2024.
ADAMS Accession No	ML24093A089
Amendment No(s)	214.

LICENSE AMENDMENT ISSUANCE(S)—Continued

Brief Description of Amendment(s)	The amendment revised the River Bend Renewed Facility Operating License No. NPF-47 to add a new license condition to allow for the implementation of 10 CFR 50.69, "Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors."
Public Comments Received as to Proposed NSHC (Yes/No).	No.
Florida Power & Light Company, et al.; St. Lucie Plant, Unit Nos. 1 and 2; St. Lucie County, FL	
Docket No(s)	50-335, 50-389.
Amendment Date	March 12, 2024.
ADAMS Accession No	ML24017A209.
Amendment No(s)	254 (Unit 1) and 209 (Unit 2).
Brief Description of Amendment(s)	The amendments modified the licensing basis by the addition of a license condition to allow for the implementation of the provisions of 10 CFR 50.69, "Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors."
Public Comments Received as to Proposed NSHC (Yes/No).	No.
NextEra Energy Seabrook, LLC.; Seabrook Station, Unit No. 1; Rockingham County, NH	
Docket No(s)	50-443.
Amendment Date	May 7, 2024.
ADAMS Accession No	ML24046A051.
Amendment No(s)	174.
Brief Description of Amendment(s)	The amendment revised the applicability of the figures in the technical specifications (TSs) for the reactor coolant system pressure-temperature (P-T) limits. This modified the period of applicability specified in the P-T limits curves of TS Figure 3.4-2, Reactor Coolant System Heatup Limitations—Applicable to 55 effective full-power years (EFPY), and Figure 3.4-3, Reactor Coolant System Cooldown Limitations—applicable to 55 EFPY, and Figure 3.4-4, Maximum Allowable power operated Setpoints for cold overpressure protection system, and conforming changes to the TS Index by updating from 55 EFPY to 52.6 EFPY.
Public Comments Received as to Proposed NSHC (Yes/No).	Yes.
Northern States Power Company—Minnesota; Prairie Island Nuclear Generating Plant, Unit Nos. 1 and 2; Goodhue County, MN	
Docket No(s)	50-282, 50-306.
Amendment Date	May 1, 2024.
ADAMS Accession No	ML24071A116.
Amendment No(s)	244 (Unit 1) and 232 (Unit 2).
Brief Description of Amendment(s)	The amendments revised Technical Specification (TS) 3.7.8, "Cooling Water (CL) System," required actions for Condition B from verification of operability of both CL pumps that supply the operable CL header to verification of the operability of a safeguards CL pump supplying the operable CL header. The amendments also remove reference to an expired one-time allowance for the completion time for TS 3.7.8 required action B.1.
Public Comments Received as to Proposed NSHC (Yes/No).	No.
Southern Nuclear Operating Company, Inc.; Vogtle Electric Generating Plant, Unit 3; Burke County, GA	
Docket No(s)	52-025.
Amendment Date	May 11, 2024.
ADAMS Accession No	ML24101A211.
Amendment No(s)	198.
Brief Description of Amendment(s)	The amendment changed Technical Specification (TS) 5.5.13, "Ventilation Filter Testing Program (VFTP)," to provide an exception to the 24-month testing frequency. The exception deferred the next required performance until prior to startup from the first refueling outage. This exception applies to in-place penetration and system bypass testing of the high efficiency particulate air (HEPA) filter, in place penetration and system bypass testing of the charcoal adsorber, and pressure drop testing across the HEPA filter, the charcoal adsorber, and the post filter, as specified in TSs 5.5.13.a.1, 5.5.13.a.2, and 5.5.13.a.4, respectively.
Public Comments Received as to Proposed NSHC (Yes/No).	Yes.
Tennessee Valley Authority; Watts Bar Nuclear Plant, Unit 1; Rhea County, TN	
Docket No(s)	50-390.
Amendment Date	May 16, 2024.
ADAMS Accession No	ML24100A764.
Amendment No(s)	166.
Brief Description of Amendment(s)	The amendment revised Watts Bar Nuclear Plant, Unit 1, Technical Specification 3.8.2, "AC [Alternating Current] Sources—Shutdown," to remove the Note regarding the C-S diesel generator.

LICENSE AMENDMENT ISSUANCE(S)—Continued

Public Comments Received as to Proposed
NSHC (Yes/No).

No.

Dated: June 5, 2024.

For the Nuclear Regulatory Commission.

Jamie Pelton,

*Deputy Director, Division of Operating
Reactor Licensing, Office of Nuclear Reactor
Regulation.*

[FR Doc. 2024–12704 Filed 6–10–24; 8:45 am]

BILLING CODE 7590–01–P

POSTAL REGULATORY COMMISSION

[Docket Nos. CP2020–200; CP2023–136;
MC2024–343 and CP2024–351; MC2024–344
and CP2024–352; MC2024–345 and CP2024–
353]

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:* June 12, 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), 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):* CP2020–200; *Filing Title:* Notice of the United States Postal Service of Filing Modification Three to International Priority Airmail, Commercial ePacket, Priority Mail Express International, Priority Mail International & First-Class Package International Service with Reseller Contract 3 Negotiated Service Agreement; *Filing Acceptance Date:* June 4, 2024; *Filing Authority:* 39 CFR 3035.105; *Public Representative:* Katalin K. Clendenin; *Comments Due:* June 12, 2024.

2. *Docket No(s):* *Docket No(s):* CP2020–200; *Filing Title:* Notice of the United States Postal Service of Filing Modification One to Priority Mail

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).

Express International, Priority Mail International & First-Class Package International Service Contract 18; *Filing Acceptance Date:* June 4, 2024; *Filing Authority:* 39 CFR 3035.105; *Public Representative:* Katalin K. Clendenin; *Comments Due:* June 12, 2024.

3. *Docket No(s):* MC2024–343 and CP2024–351; *Filing Title:* USPS Request to Add Priority Mail Express, Priority Mail & USPS Ground Advantage Contract 97 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* June 4, 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:* June 12, 2024.

4. *Docket No(s):* MC2024–344 and CP2024–352; *Filing Title:* USPS Request to Add Priority Mail Express, Priority Mail & USPS Ground Advantage Contract 98 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* June 4, 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:* June 12, 2024.

5. *Docket No(s):* MC2024–345 and CP2024–353; *Filing Title:* USPS Request to Add Priority Mail Express, Priority Mail & USPS Ground Advantage Contract 99 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* June 4, 2024; *Filing Authority:* 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative:* Alireza Motameni; *Comments Due:* June 12, 2024.

This Notice will be published in the **Federal Register**.

Erica A. Barker,
Secretary.

[FR Doc. 2024–12674 Filed 6–10–24; 8:45 am]

BILLING CODE 7710–FW–P

POSTAL SERVICE

Sunshine Act Meetings

FEDERAL REGISTER CITATION OF PREVIOUS ANNOUNCEMENT: 89 FR 44718.

PREVIOUSLY ANNOUNCED TIME AND DATE OF THE MEETING: Meeting of the Board of Governors, Tuesday, June 11, 2024, at 11:00 a.m.

PLACE: Washington, DC.

STATUS: Closed.

CHANGES IN THE MEETING: Time and date of meeting changed.

REVISED TIME: Tuesday, July 2, 2024, at 4:00 p.m.

CONTACT PERSON FOR MORE INFORMATION: Michael J. Elston, Secretary of the Board, U.S. Postal Service, 475 L'Enfant Plaza SW, Washington, DC 20260-1000. Telephone: (202) 268-4800.

Michael J. Elston,
Secretary.

[FR Doc. 2024-12827 Filed 6-7-24; 11:15 am]

BILLING CODE 7710-12-P

SECURITIES AND EXCHANGE COMMISSION

[Investment Company Act Release No. 35213; File No. 812-15395]

HPS Corporate Lending Fund, et al.

June 5, 2024.

AGENCY: Securities and Exchange Commission (“Commission” or “SEC”).

ACTION: Notice.

Notice of application for an order (“Order”) under sections 17(d) and 57(i) of the Investment Company Act of 1940 (the “Act”) and rule 17d-1 under the Act to permit certain joint transactions otherwise prohibited by sections 17(d) and 57(a)(4) of the Act and rule 17d-1 under the Act.

SUMMARY OF APPLICATION: Applicants request an order to amend a previous order granted by the Commission that permits certain business development companies (“BDCs”) and closed-end management investment companies to co-invest in portfolio companies with each other and with certain affiliated investment entities.

APPLICANTS: HPS Corporate Lending Fund, HPS Investment Partners, LLC, Brickyard Direct Lending Fund, L.P., Core Senior Lending Fund (A-A), L.P., Core Senior Lending Fund, L.P., HPS DPT Direct Lending Fund, L.P., Hinode Direct Lending 2017 Fund, L.P., Kitty Hawk Credit Fund, L.P., Core Senior Lending Master Fund (PB), L.P., HPS Core Senior Lending Portfolio (PB) II, L.P., Credit Value Master Fund 2016, L.P., Credit Value Master Fund V, L.P., Credit Value Ontario Fund V, L.P., Credit Value Master Fund VI, L.P., European Asset Value Fund (USD) II, L.P., European Asset Value Offshore Fund (USD) II, L.P., European Asset Value Offshore Fund II, L.P., HPS European Liquid Loan Opportunities Master Fund, L.P., HPS Mezzanine Partners 2019, L.P., HPS Offshore

L.P., HPS Offshore Mezzanine Partners 2019 Europe, SCSp, HPS Offshore Mezzanine Partners 2019, L.P., HPS Special Situations Opportunity Fund, L.P., HPS Special Situations Opportunity Offshore Fund, L.P., HPS Specialty Loan Europe Fund V, SCSp, HPS Specialty Loan Fund (JPY) V, L.P., HPS Specialty Loan Fund V, L.P., HPS Specialty Loan Fund V-L, L.P., HPS Specialty Loan International Fund V, SCSp, HPS Specialty Loan International Fund V-L, L.P., Institutional Credit Master Fund, L.P., Liquid Loan Opportunities Master Fund, L.P., Mayfair Alternative Credit Funds ICAV, Mezzanine Partners III, L.P., Offshore Mezzanine Partners III Co-Invest, L.P., Offshore Mezzanine Partners III, L.P., Real Estate Credit Solutions Fund II, L.P., Real Estate Credit Solutions Offshore Fund II, L.P., Specialty Loan Fund 2016, L.P., Specialty Loan Fund 2016-L, L.P., Specialty Loan Institutional Fund 2016-L, L.P., Aspen Co-Invest, L.P., Bronco Co-Invest, L.P., Endurance II Co-Invest, L.P., Galaxy III Co-Invest, L.P., Milano Co-Invest, L.P., Neptune Co-Invest, L.P., Patriot Co-Invest, L.P., Aiguilles Rouges Irish Specialty Loan Fund plc, Aiguilles Rouges Specialty Loan Fund, L.P., Cactus Direct Lending Fund, L.P., Cardinal Fund, L.P., CST Specialty Loan Fund, L.P., Falcon Credit Fund, L.P., GIM Credit Lux S.A., GIM Credit Master Lux S.à r.l., GIM II, L.P., GIM, L.P., HC Direct Lending Fund, L.P., HN Co-Investment Fund, L.P., HPS Core Senior Lending Co-Invest, L.P., HPS Halite 2020 Direct Lending Fund Limited, HPS KP Mezz 2019 Co-Invest, L.P., HPS Magnetite Energy & Power Credit Fund, L.P., HPS Magnetite Energy & Power Credit Offshore Fund, L.P., HPS Ocoee Specialty Loan Fund, L.P., HPS OH Co-Investment Fund, L.P., HPS PA Co-Investment Fund, L.P., HPS RR Specialty Loan Fund, L.P., HPS VG Co-Investment Fund, L.P., Jade Real Assets Fund, L.P., Mauna Kea Fund, L.P., Moreno Street Direct Lending Fund, L.P., NDT Senior Loan Fund, L.P., Presidio Loan Fund, L.P., Private Loan Opportunities Fund, L.P., Red Cedar Fund 2016, L.P., Sandlapper Credit Fund, L.P., SC Strategic Investment Fund, L.P., Specialty Loan Fund—CX-2, L.P., Specialty Loan VG Fund, L.P., AP Mezzanine Partners III, L.P., HPS AP Mezzanine Partners 2019, L.P., HPS Hinode Mezzanine Partners 2020, L.P., Specialty Loan Ontario Fund 2016, L.P., EL Specialty Loan Secondary Fund, L.P., HPS Offshore Strategic Investment Partners V, L.P., HPS Strategic Investment Partners V, L.P., HPS AP Strategic Investment Partners V, L.P.,

HPS AD Co-Investment Holdings, L.P., HPS Investment Partners (UK) LLP, HPS Investment Partners (HK), Limited, HPS Investments Partners (AUS) Pty Ltd., HPS ALSC Management, LLC, HPS Mezzanine Partners, LLC, HPS Mezzanine Partners II, LLC, HPS Mezzanine Management III, LLC, HPS Mezzanine Management 2019, LLC, HPS Opportunities SL Management, LLC, HPS RE Management, LLC, HPS Investment Partners CLO (US), LLC, HPS Investment Partners CLO (UK) LLP, HPS EF GP, LLC, HPS EL SLF 2016 GP, LLC, CGC, LLC, CGC III Partners LLC, HPS Strategic Investment Management V, LLC, HPS Elbe Unlevered Direct Lending Fund, SCSp, HPS Specialty Loan Ontario Fund V, L.P., Shelby Co-Invest, L.P., Core Senior Lending Fund II, SCSp, Core Senior Lending International Fund II, SCSp, HPS Offshore Strategic Investment Partners V Europe, SCSp, Segovia Loan Advisors (UK) LLP, HPS Core Senior Lending International Fund (EUR) II, SCSp, HPS Specialty Loan Fund (EUR) V, L.P., Proxima Co-Invest, L.P., Proxima Onshore Co-Invest, L.P., HPS Specialty Loan Fund TX, L.P., Salus Co-Invest, L.P., Credit Value Fund VII, L.P., Credit Value Offshore Fund VII, L.P., HPS Mint Co-Invest, L.P., HPS Special Situations Opportunity Offshore Fund II, SCSp, Credit Value Ontario Fund VII, L.P., HPS Special Situations Opportunity Fund II, L.P., HN SIP V Co-Investment Fund, L.P., Core Senior Lending Fund II Feeder, L.P., HPS KP SIP V Co-Investment Fund, L.P., HPS Energy & Power IA Fund, L.P., HPS Asset Value Lux Fund (USD) III, SCSp, HPS Asset Value Lux Fund III, SCSp, HPS Star Private Credit Fund SCSp, Core Senior Lending International Fund (EUR) II—G, SCSp, HPS AD SIP V Co-Investment Fund, L.P., Eastwood Co-Invest, L.P., HPS Strategic Investment Partners V Feeder, L.P., HPS—SC Strategic Investment Fund II, L.P., HPS Everest Co-Investment Fund, L.P., Maple Co-Invest, L.P., HPS Asset Value Fund (USD) III, L.P., Luther Co-Invest, L.P., Minerva Co-Invest, L.P., HPS Hinode Strategic Investment Partners V 2021, L.P., Marilyn Co-Invest, L.P., HPS Investment Partners (SG) Pte. Ltd., HPS A-Life Direct Lending Fund, L.P., Specialty Loan Fund International Fund VI, SCSp, Specialty Loan Fund VI, SCSp, Specialty Loan Fund VI—L, SCSp, Specialty Loan International Fund VI—L, SCSp, HPS Loan Management 2013–2, Ltd., HPS Loan Management 3–2014, Ltd., HPS Loan Management 4–2014, Ltd., HPS Loan Management 5–2015, Ltd., HPS Loan Management 6–2015, Ltd., HPS Loan Management 7–2015,

Ltd., HPS Loan Management 8–2016, Ltd., HPS Loan Management 9–2016, Ltd., HPS Loan Management 10–2016, Ltd., HPS Loan Management 11–2017, Ltd., HPS Loan Management 12–2018, Ltd., HPS Loan Management 13–2018, Ltd., HPS Loan Management 14–2019, Ltd., HPS Loan Management 15–2019, Ltd., HPS Loan Management 2021–16, Ltd., HPS Loan Management 2022–17, Ltd., HPS Loan Management 2022–19, Ltd., Strata CLO II, Ltd., Arcadia Warehouse 2022, Ltd., Aqueduct European CLO 1–2017 DAC, Aqueduct European CLO 2–2017 DAC, Aqueduct European CLO 3–2019 DAC, Aqueduct European CLO 4–2019 DAC, Aqueduct European CLO 5–2020 DAC, Aqueduct European CLO 6–2021 DAC, Aqueduct European CLO 7–2022 DAC, Aqueduct European CLO 8–2022 DAC, Aqueduct European CLO 9–2022 DAC, Segovia European CLO 1–2014 DAC, Segovia European CLO 2–2016 DAC, Segovia European CLO 3–2017 DAC, Segovia European CLO 4–2017 DAC, Segovia European CLO 5–2018 DAC, Segovia European CLO 6–2019 DAC, HPS AZ SIP V Co-Investment Fund, SCSp, HPS Specialty Loan Fund (EUR) VI, SCSp, HPS HLBL Co-Investment Fund, L.P., Palisades CLO, LLC, Institutional Credit Europe Fund, SCSp, Piccadilly Co-Invest, L.P., Core Senior Lending International Fund II–S, SCSp, HPS Advisors, LLC, HPS Specialty Loan Institutional Fund VI–L, L.P., HPS Specialty Loan Fund VI Feeder, L.P., HPS Specialty Loan International Fund VI Co-Invest, SCSp, HPS Specialty Loan Fund VI Co-Invest, SCSp, HPS PA SIP V Co-Investment Fund, L.P., HPS Loan Management 2023–17, Ltd, Strata CLO I, Ltd., HPS Loan Management 2023–19, Ltd., HPS Sustainability & Energy Transition Fund, L.P., HPS Offshore Sustainability & Energy Transition Fund, SCSp, HN Private Credit Fund, L.P., HPS Specialty Loan International Fund (EUR) VI, SCSp, HPS Hinode Strategic Investment Partners 2023, L.P., HK Co-Investment Fund, LLC, HPS Black Knight 1922 Specialty Loan Fund, LLC, HPS Garden Private Credit Fund, L.P., HN Direct Lending Co-Investment Fund 2023, L.P., HPS Corporate Capital Solutions Fund, HPS ART Direct Lending Fund, SCSp, Capricorn Co-Invest, L.P., HPS Roadrunner Specialty Loan Fund, L.P., Boost Co-Invest, L.P., CST Core Senior Lending Fund, L.P., Asset Value Platform, L.P., SLF VI WC Aggregator, L.P., and HPS Anchor Direct Lending Co-Investment Fund, SCSp.

FILING DATES: The application was filed on October 12, 2022, and amended on May 3, 2023, August 22, 2023, and November 8, 2023.

HEARING OR NOTIFICATION OF HEARING: An order granting the requested relief will be issued unless the Commission orders a hearing. Interested persons may request a hearing on any application by emailing the SEC's Secretary at *Secretarys-Office@sec.gov* and serving the Applicants with a copy of the request by email, if an email address is listed for the relevant Applicant below, or personally or by mail, if a physical address is listed for the relevant Applicant below. Hearing requests should be received by the Commission by 5:30 p.m. on, July 1, 2024, and should be accompanied by proof of service on applicants, in the form of an affidavit or, for lawyers, a certificate of service. Pursuant to rule 0–5 under the Act, hearing requests should state the nature of the writer's interest, any facts bearing upon the desirability of a hearing on the matter, the reason for the request, and the issues contested. Persons who wish to be notified of a hearing may request notification by emailing the Commission's Secretary at *Secretarys-Office@sec.gov*.

ADDRESSES: The Commission: *Secretarys-Office@sec.gov*. Applicants: Yoohyun K. Choi, HPS Advisors, LLC, at *kathy.choi@hpspartners.com*; and Richard Horowitz, Esq., Dechert LLP, at *richard.horowitz@dechert.com*.

FOR FURTHER INFORMATION CONTACT: Kieran G. Brown, Senior Counsel, or Terri Jordan, Branch Chief, at (202) 551–6825 (Division of Investment Management, Chief Counsel's Office).

SUPPLEMENTARY INFORMATION: For Applicants' representations, legal analysis, and conditions, please refer to Applicants' third amended and restated application, dated November 8, 2023, which may be obtained via the Commission's website by searching for the file number at the top of this document, or for an Applicant using the Company name search field, on the SEC's EDGAR system. The SEC's EDGAR system may be searched at <http://www.sec.gov/edgar/searchedgar/legacy/companysearch.html>. You may also call the SEC's Public Reference Room at (202) 551–8090.

For the Commission, by the Division of Investment Management, under delegated authority.

Sherry R. Haywood,
Assistant Secretary.

[FR Doc. 2024–12684 Filed 6–10–24; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–100278; File No. SR–NYSEARCA–2024–46]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend Rule 7.19–E

June 5, 2024.

Pursuant to Section 19(b)(1)¹ of the Securities Exchange Act of 1934 (“Act”)² and Rule 19b–4 thereunder,³ notice is hereby given that, on May 28, 2024, NYSE Arca, Inc. (“NYSE Arca” or the “Exchange”) filed with the Securities and Exchange Commission (“Commission”) the proposed rule change as described in Items I and II, below, which Items have been prepared by the self-regulatory organization. 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 Rule 7.19–E to make additional pre-trade risk controls available to Entering Firms. The proposed rule change is available on the Exchange's website at www.nyse.com, 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 self-regulatory organization 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 those 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 parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Rule 7.19–E to make additional pre-trade risk controls available to Entering Firms.

¹ 15 U.S.C. 78s(b)(1).

² 15 U.S.C. 78a.

³ 17 CFR 240.19b–4.

Background and Proposal

In 2020, in order to assist ETP Holders' efforts to manage their risk, the Exchange amended its rules to add Rule 7.19–E (Pre-Trade Risk Controls),⁴ which established a set of optional pre-trade risk controls by which Entering Firms and their designated Clearing Firms⁵ could set credit limits and other pre-trade risk controls for an Entering Firm's trading on the Exchange and authorize the Exchange to take action if those credit limits or other pre-trade risk controls are exceeded.

The Exchange has recently received several requests from market participants to create an additional risk control to restrict the overall rate of orders. The Exchange notes that several other exchanges—including the Cboe equities exchanges, MEMX, and the MIAx Pearl equities exchange (“MIAx Pearl”)⁶—currently offer risk controls substantially similar to the one proposed here. As such, market participants are already familiar with these risk checks, such that the ones proposed by the Exchange in this filing are not novel.

In light of these requests, the Exchange proposes to amend Rule 7.19–E(b)(2) to add a new subparagraph (G), which would provide that the Single Order Risk Controls available to Entering Firms would include “controls to restrict the overall rate of orders.”

As with the Exchange's existing risk controls, use of the pre-trade risk controls proposed herein would be optional. The Exchange proposes no other changes to Rule 7.19–E or its Commentary.

Continuing Obligations of ETP Holders Under Rule 15c3–5

The proposed Pre-Trade Risk Controls described here are meant to supplement, and not replace, the ETP Holders' own internal systems, monitoring, and procedures related to risk management. The Exchange does not guarantee that these controls will be sufficiently

comprehensive to meet all of an ETP Holder's needs, the controls are not designed to be the sole means of risk management, and using these controls will not necessarily meet an ETP Holder's obligations required by Exchange or federal rules (including, without limitation, the Rule 15c3–5 under the Act⁷ (“Rule 15c3–5”). Use of the Exchange's Pre-Trade Risk Controls will not automatically constitute compliance with Exchange or federal rules and responsibility for compliance with all Exchange and SEC rules remains with the ETP Holder.⁸

Timing and Implementation

The Exchange anticipates implementing the proposed change in the second quarter of 2024 and, in any event, will implement the proposed rule change no later than the end of September 2024. The Exchange will announce the timing of such changes by Trader Update.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with Section 6(b) of the Act,⁹ in general, and furthers the objectives of Section 6(b)(5) of the Act,¹⁰ in particular, because it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, 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, and because it is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

Specifically, the Exchange believes that the proposed rule change will remove impediments to and perfect the mechanism of a free and open market and a national market system because the proposed additional Pre-Trade Risk Control would provide Entering Firms with enhanced abilities to manage their risk with respect to orders on the Exchange. The proposed additional Pre-

Trade Risk Control is not novel; it is based on existing risk settings already in place on the Cboe, MEMX, and MIAx Pearl exchanges and market participants are already familiar with the types of protections that the proposed risk control affords.¹¹ As such, the Exchange believes that the proposed additional Pre-Trade Risk Control would provide a means to address potentially market-impacting events, helping to ensure the proper functioning of the market.

In addition, the Exchange believes that the proposed rule change will protect investors and the public interest because the proposed additional Pre-Trade Risk Control is a form of impact mitigation that will aid Entering Firms in minimizing their risk exposure and reduce the potential for disruptive, market-wide events. The Exchange understands that ETP Holders implement a number of different risk-based controls, including those required by Rule 15c3–5. The controls proposed here will serve as an additional tool for Entering Firms to assist them in identifying any risk exposure. The Exchange believes the proposed additional Pre-Trade Risk Control will assist Entering Firms in managing their financial exposure which, in turn, could enhance the integrity of trading on the securities markets and help to assure the stability of the financial system.

Finally, the Exchange believes that the proposed rule change does not unfairly discriminate among the Exchange's ETP Holders because use of the proposed additional Pre-Trade Risk Control is optional and is not a prerequisite for participation on the Exchange.

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 that is not necessary or appropriate in furtherance of the purposes of the Act. In fact, the Exchange believes that the proposal will have a positive effect on competition because, by providing Entering Firms additional means to monitor and control risk, the proposed rule will increase confidence in the proper functioning of the markets. The Exchange believes the proposed additional Pre-Trade Risk Control will assist Entering Firms in managing their financial exposure which, in turn, could enhance the integrity of trading on the securities markets and help to assure the stability of the financial system. As a result, the level of competition should increase as

⁴ See Securities Exchange Act Release No. 88904 (May 19, 2020), 85 FR 31560 (May 26, 2020) (SR–NYSEArca–2020–43). Later, in 2023, the Exchange amended its rules to make additional pre-trade risk controls available to Entering Firms. See Securities Exchange Act Release No. 96921 (February 14, 2023), 88 FR 10597 (February 21, 2023) (SR–NYSEARCA–2023–13).

⁵ The terms “Entering Firm” and “Clearing Firm” are defined in Rule 7.19–E.

⁶ See, e.g., Cboe BZX Equities Rule 11.13 interpretation [sic].01 paragraph (f); Cboe BYX Equities Rule 11.13 interpretation [sic].01 paragraph (f); Cboe EDGA Equities Rule 11.10 interpretation [sic].01 paragraph (f); Cboe EDGX Equities Rule 11.10 interpretation [sic].01 paragraph (f); MEMX Rule 11.10 interpretation [sic].01 paragraph (f); and MIAx Pearl Equities Rule 2618(a)(1)(H).

⁷ See 17 CFR 240.15c3–5.

⁸ See also Commentary .01 to Rule 7.19–E, which provides that “[t]he pre-trade risk controls described in this Rule are meant to supplement, and not replace, the ETP Holder's own internal systems, monitoring and procedures related to risk management and are not designed for compliance with Rule 15c3–5 under the Exchange Act. Responsibility for compliance with all Exchange and SEC rules remains with the ETP Holder.”

⁹ 15 U.S.C. 78f(b).

¹⁰ 15 U.S.C. 78f(b)(5).

¹¹ See *supra* note 6.

public confidence in the markets is solidified.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act¹² and Rule 19b-4(f)(6) thereunder.¹³ 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) of the Act¹⁴ and Rule 19b-4(f)(6) thereunder.¹⁵

A proposed rule change filed under Rule 19b-4(f)(6)¹⁶ normally does not become operative prior to 30 days after the date of the filing. However, pursuant to Rule 19b-4(f)(6)(iii),¹⁷ the Commission may designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange has requested that the Commission waive the 30-day operative delay so that the proposed rule change may become effective and operative upon filing with the Commission. The Exchange states that the proposed rule change is tied to a technological release that the Exchange plans to implement by the end of June 2024, that such release may be ready before the 30-day operative delay has elapsed, and the Exchange seeks to implement the proposed rule change without delay. The Exchange explains that the proposed rule change will assist Entering Firms in minimizing their risk exposure, which could enhance the integrity of trading on the securities markets and help to assure the stability

of the financial system, and that the proposed rule change is not novel as it is based on existing risk settings already in place on other exchanges. For these reasons, and because the proposed rule change does not raise any new or novel regulatory issues, the Commission believes that waiver of the 30-day operative delay is consistent with the protection of investors and the public interest. Accordingly, the Commission hereby waives the operative delay and designates the proposed rule change operative upon filing.¹⁸

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 change 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-NYSEARCA-2024-46 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-NYSEARCA-2024-46. 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

¹⁸ For purposes only of waiving the 30-day operative delay, the Commission also has considered the proposed rule's impact on efficiency, competition, and capital formation. See 15 U.S.C. 78c(f).

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 a.m. and 3 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-NYSEARCA-2024-46 and should be submitted on or before July 2, 2024.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.¹⁹

Sherry R. Haywood,
Assistant Secretary.

[FR Doc. 2024-12687 Filed 6-10-24; 8:45 am]

BILLING CODE 8011-01-P

SECURITIES AND EXCHANGE COMMISSION

[SEC File No. 270-348, OMB Control No. 3235-0394]

Proposed Collection; Comment Request; Extension: Rule 15g-5

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of FOIA Services, 100 F Street NE, Washington, DC 20549-2736

Notice is hereby given that pursuant to the Paperwork Reduction Act of 1995 ("PRA") (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission ("Commission") is soliciting comments on the existing collection of information provided for in Rule 15g-5—Disclosure of Compensation to Associated Persons in Connection with Penny Stock Transactions—(17 CFR 240.15g-5) under the Securities Exchange Act of 1934 (15 U.S.C. 78a *et seq.*). The Commission plans to submit this existing collection of information to the Office of Management and Budget ("OMB") for extension and approval.

¹⁹ 17 CFR 200.30-3(a)(12).

¹² 15 U.S.C. 78s(b)(3)(A)(iii).

¹³ 17 CFR 240.19b-4(f)(6).

¹⁴ 15 U.S.C. 78s(b)(3)(A).

¹⁵ 17 CFR 240.19b-4(f)(6). In addition, Rule 19b-4(f)(6)(iii) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of 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.

¹⁶ 17 CFR 240.19b-4(f)(6).

¹⁷ 17 CFR 240.19b-4(f)(6)(iii).

Rule 15g-5 requires brokers and dealers to disclose to customers the amount of compensation to be received by their sales agents in connection with penny stock transactions. The purpose of the rule is to increase the level of disclosure to investors concerning penny stocks generally and specific penny stock transactions.

The Commission estimates that approximately 170 broker-dealers will spend an average of approximately 87 hours annually to comply with the rule. Thus, the total time burden is approximately 14,790 hours per year.

Written comments are invited on: (a) 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; (b) the accuracy of the Commission's estimates of the burden of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information collected; and (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. Consideration will be given to comments and suggestions submitted by August 12, 2024.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information under the PRA unless it displays a currently valid OMB control number.

Please direct your written comments to: David Bottom, Director/Chief Information Officer, Securities and Exchange Commission, c/o John Pezzullo, 100 F Street NE, Washington, DC 20549, or send an email to: PRA_Mailbox@sec.gov.

Dated: June 5, 2024.

Sherry R. Haywood,
Assistant Secretary.

[FR Doc. 2024-12672 Filed 6-10-24; 8:45 am]

BILLING CODE 8011-01-P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34-100279; File No. SR-NYSENAT-2024-17]

Self-Regulatory Organizations; NYSE National, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend Rule 7.19

June 5, 2024.

Pursuant to Section 19(b)(1) ¹ of the Securities Exchange Act of 1934

(“Act”) ² and Rule 19b-4 thereunder, ³ notice is hereby given that on May 31, 2024, NYSE National, Inc. (“NYSE National” or the “Exchange”) filed with the Securities and Exchange Commission (“Commission”) the proposed rule change as described in Items I and II, below, which Items have been prepared by the self-regulatory organization. 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 Rule 7.19 to make additional pre-trade risk controls available to Entering Firms. The proposed rule change is available on the Exchange's website at www.nyse.com, 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 self-regulatory organization 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 those 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 parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Rule 7.19 to make additional pre-trade risk controls available to Entering Firms.

Background and Proposal

In 2020, in order to assist ETP Holders' efforts to manage their risk, the Exchange amended its rules to add Rule 7.19 (Pre-Trade Risk Controls), ⁴ which established a set of optional pre-trade risk controls by which Entering Firms

and their designated Clearing Firms ⁵ could set credit limits and other pre-trade risk controls for an Entering Firm's trading on the Exchange and authorize the Exchange to take action if those credit limits or other pre-trade risk controls are exceeded.

The Exchange has recently received several requests from market participants to create an additional risk control to restrict the overall rate of orders. The Exchange notes that several other exchanges—including the Cboe equities exchanges, MEMX, and the MIAx Pearl equities exchange (“MIAx Pearl”) ⁶—currently offer risk controls substantially similar to the one proposed here. As such, market participants are already familiar with these risk checks, such that the ones proposed by the Exchange in this filing are not novel.

In light of these requests, the Exchange proposes to amend Rule 7.19(b)(2) to add a new subparagraph (G), which would provide that the Single Order Risk Controls available to Entering Firms would include “controls to restrict the overall rate of orders.”

As with the Exchange's existing risk controls, use of the pre-trade risk controls proposed herein would be optional. The Exchange proposes no other changes to Rule 7.19 or its Commentary.

Continuing Obligations of ETP Holders Under Rule 15c3-5

The proposed Pre-Trade Risk Controls described here are meant to supplement, and not replace, the ETP Holders' own internal systems, monitoring, and procedures related to risk management. The Exchange does not guarantee that these controls will be sufficiently comprehensive to meet all of an ETP Holder's needs, the controls are not designed to be the sole means of risk management, and using these controls will not necessarily meet an ETP Holder's obligations required by Exchange or federal rules (including, without limitation, the Rule 15c3-5 under the Act ⁷ (“Rule 15c3-5”). Use of the Exchange's Pre-Trade Risk Controls will not automatically constitute compliance with Exchange or federal rules and responsibility for compliance

⁵ The terms “Entering Firm” and “Clearing Firm” are defined in Rule 7.19.

⁶ See, e.g., Cboe BZX Equities Rule 11.13 Interpretations and Policies .01 paragraph (f); Cboe BYX Equities Rule 11.13 Interpretations and Policies .01 paragraph (f); Cboe EDGA Equities Rule 11.10 Interpretations and Policies .01 paragraph (f); Cboe EDGX Equities Rule 11.10 Interpretations and Policies .01 paragraph (f); MEMX Rule 11.10 Interpretations and Policies .01 paragraph (f); and MIAx Pearl Equities Rule 2618(a)(1)(H).

⁷ See 17 CFR 240.15c3-5.

² 15 U.S.C. 78a.

³ 17 CFR 240.19b-4.

⁴ See Securities Exchange Act Release No. 88905 (May 19, 2020), 85 FR 31582 (May 26, 2020) (SR-NYSENAT-2020-17). Later, in 2023, the Exchange amended its rules to make additional pre-trade risk controls available to Entering Firms. See Securities Exchange Act Release No. 96919 (February 14, 2023), 88 FR 10569 (February 21, 2023) (SR-NYSENAT-2023-07).

¹ 15 U.S.C. 78s(b)(1).

with all Exchange and SEC rules remains with the ETP Holder.⁸

Timing and Implementation

The Exchange anticipates implementing the proposed change in the second quarter of 2024 and, in any event, will implement the proposed rule change no later than the end of September 2024. The Exchange will announce the timing of such changes by Trader Update.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with Section 6(b) of the Act,⁹ in general, and furthers the objectives of Section 6(b)(5) of the Act,¹⁰ in particular, because it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, 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, and because it is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

Specifically, the Exchange believes that the proposed rule change will remove impediments to and perfect the mechanism of a free and open market and a national market system because the proposed additional Pre-Trade Risk Control would provide Entering Firms with enhanced abilities to manage their risk with respect to orders on the Exchange. The proposed additional Pre-Trade Risk Control is not novel; it is based on existing risk settings already in place on the Cboe, MEMX, and MIAX Pearl exchanges and market participants are already familiar with the types of protections that the proposed risk control affords.¹¹ As such, the Exchange believes that the proposed additional Pre-Trade Risk Control would provide a means to address potentially market-impacting events, helping to ensure the proper functioning of the market.

⁸ See also Commentary .01 to Rule 7.19, which provides that “[t]he pre-trade risk controls described in this Rule are meant to supplement, and not replace, the ETP Holder’s own internal systems, monitoring and procedures related to risk management and are not designed for compliance with Rule 15c3–5 under the Exchange Act. Responsibility for compliance with all Exchange and SEC rules remains with the ETP Holder.”

⁹ 15 U.S.C. 78f(b).

¹⁰ 15 U.S.C. 78f(b)(5).

¹¹ See *supra* note 6.

In addition, the Exchange believes that the proposed rule change will protect investors and the public interest because the proposed additional Pre-Trade Risk Control is a form of impact mitigation that will aid Entering Firms in minimizing their risk exposure and reduce the potential for disruptive, market-wide events. The Exchange understands that ETP Holders implement a number of different risk-based controls, including those required by Rule 15c3–5. The controls proposed here will serve as an additional tool for Entering Firms to assist them in identifying any risk exposure. The Exchange believes the proposed additional Pre-Trade Risk Control will assist Entering Firms in managing their financial exposure which, in turn, could enhance the integrity of trading on the securities markets and help to assure the stability of the financial system.

Finally, the Exchange believes that the proposed rule change does not unfairly discriminate among the Exchange’s ETP Holders because use of the proposed additional Pre-Trade Risk Control is optional and is not a prerequisite for participation on the Exchange.

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 that is not necessary or appropriate in furtherance of the purposes of the Act. In fact, the Exchange believes that the proposal will have a positive effect on competition because, by providing Entering Firms additional means to monitor and control risk, the proposed rule will increase confidence in the proper functioning of the markets. The Exchange believes the proposed additional Pre-Trade Risk Control will assist Entering Firms in managing their financial exposure which, in turn, could enhance the integrity of trading on the securities markets and help to assure the stability of the financial system. As a result, the level of competition should increase as public confidence in the markets is solidified.

C. Self-Regulatory Organization’s Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act¹² and Rule 19b–4(f)(6) thereunder.¹³ 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) of the Act¹⁴ and Rule 19b–4(f)(6) thereunder.¹⁵

A proposed rule change filed under Rule 19b–4(f)(6)¹⁶ normally does not become operative prior to 30 days after the date of the filing. However, pursuant to Rule 19b–4(f)(6)(iii),¹⁷ the Commission may designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange has requested that the Commission waive the 30-day operative delay so that the proposed rule change may become effective and operative upon filing with the Commission. The Exchange states that the proposed rule change is tied to a technological release that the Exchange plans to implement by the end of June 2024, that such release may be ready before the 30-day operative delay has elapsed, and the Exchange seeks to implement the proposed rule change without delay. The Exchange explains that the proposed rule change will assist Entering Firms in minimizing their risk exposure, which could enhance the integrity of trading on the securities markets and help to assure the stability of the financial system, and that the proposed rule change is not novel as it is based on existing risk settings already in place on other exchanges. For these reasons, and because the proposed rule change does not raise any new or novel regulatory issues, the Commission believes that waiver of the 30-day operative delay is consistent with the protection of investors and the public

¹² 15 U.S.C. 78s(b)(3)(A)(iii).

¹³ 17 CFR 240.19b–4(f)(6).

¹⁴ 15 U.S.C. 78s(b)(3)(A).

¹⁵ 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6)(iii) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of 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.

¹⁶ 17 CFR 240.19b–4(f)(6).

¹⁷ 17 CFR 240.19b–4(f)(6)(iii).

interest. Accordingly, the Commission hereby waives the operative delay and designates the proposed rule change operative upon filing.¹⁸

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 change 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-NYSENAT-2024-17 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-NYSENAT-2024-17. 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 a.m. and 3 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-NYSENAT-2024-17 and should be submitted on or before July 2, 2024.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.¹⁹

Sherry R. Haywood,
Assistant Secretary.

[FR Doc. 2024-12688 Filed 6-10-24; 8:45 am]

BILLING CODE 8011-01-P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34-100274; File No. SR-ICC-2024-003]

Self-Regulatory Organizations; ICE Clear Credit LLC; Order Approving Proposed Rule Change Relating to the ICC Collateral Risk Management Framework

June 5, 2024.

I. Introduction

On April 16, 2024, ICE Clear Credit LLC ("ICC") filed with the Securities and Exchange Commission ("Commission"), pursuant to Section 19(b)(2) of the Securities Exchange Act of 1934 (the "Act")¹ and Rule 19b-4 thereunder,² a proposed rule change to revise its Collateral Risk Management Framework ("CRMF"). The proposed rule change was published for comment in the **Federal Register** on April 26, 2024.³ The Commission did not receive comments regarding the proposed rule change. For the reasons discussed below, the Commission is approving the proposed rule change.

¹⁹ 17 CFR 200.30-3(a)(12).

¹ 15 U.S.C. 78s(b)(1).

² 17 CFR 240.19b-4.

³ Self-Regulatory Organizations; ICE Clear Credit LLC; Notice of Filing of Proposed Rule Change Relating to the ICC Collateral Risk Management Framework; Exchange Act Release No. 100008 (Apr. 22, 2024), 89 FR 32496 (Apr. 26, 2024) (File No. SR-ICC-2024-003) ("Notice").

II. Description of the Proposed Rule Change

ICC is registered with the Commission as a clearing agency for the purpose of clearing credit default swaps ("CDS") contracts. The CRMF describes ICC's risk management methodology for the collateral it accepts from Clearing Participants to collateralize their individual credit exposure to ICC, including a description of ICC's quantitative risk management approach that accounts for the risk associated with fluctuations of collateral asset prices (*i.e.*, "haircuts"). Collateral used to cover obligations are subject to a "haircut" assessment, where the assets are priced and posted at a discount to account for certain market risks. The current CRMF contemplates two risk measures for the haircut model approach—a 2-day 99.9% Value-at-Risk ("VaR") and a 5-day Expected Shortfall ("ES")—and requires ICC to use the measure that produces the more conservative result. Based on a comprehensive review of its risk calculations and data, ICC has determined that VaR has never produced the more conservative measurement and, therefore, ICC has always used the ES measurement instead of VaR.⁴ These risk calculations and data also show that ES will continue to produce more conservative results compared to VaR in essentially all circumstances going forward.

Based on these results, the purpose of the proposed rule change is to amend ICC's CRMF to permit ICC to rely solely on the ES to establish its haircut factors for the purposes of pricing and posting collateral. To do so, the proposed rule change would remove all references to the VaR from the CRMF.

The proposed rule change also would remove, renumber, and revise certain figures in the CRMF. The current CRMF contains various charts, graphs, and other figures (collectively, "Figures") by which ICC displays the data used to establish the relevant measurements, including Figures relevant to both the VaR and ES measurements. To effectively remove all references to VaR from the CRMF, the proposed rule change also would remove and revise certain Figures as necessary to effectuate the removal of VaR from the CRMF. Specifically, in connection with the deletion of the 2-day 99.9% VaR risk measure, the proposed rule change

⁴ See Notice, *supra* note 3, at 32496. ICC has provided responses to Commission requests for collateral risk data and analysis as part of its confidential Exhibit 3 to File No. SR-ICC-2024-003. The confidential collateral risk data that ICC provided to the Commission as part of this filing shows the risk calculations conducted by ICC.

¹⁸ For purposes only of waiving the 30-day operative delay, the Commission also has considered the proposed rule's impact on efficiency, competition, and capital formation. See 15 U.S.C. 78c(f).

would remove Figures 11, 12, 26, 27, 28, 29, 38, and 39 because those figures relate to the VaR risk measure, including 1-day 99.9% VaR which was used to calculate the VaR risk measure. As a consequence of deleting those figures, the proposed rule change would renumber the remaining figures.

ICC has further determined that altering certain Figures within the CRMF would better illustrate the data used to establish the remaining applicable ES risk measure. As discussed below, the changes are consistent with the current practice of the ICC under its current CRMF, or are being amended for illustrative purposes, and therefore will have no practical impact.

Therefore, the proposed rule change would revise certain figures to correct the label on the y-axis from percentage to bps and to make other typographical fixes, specifically Figures 16, 17, 20, 21, 28 and 30 (as renumbered). It would also correct the label on the x-axis in certain figures. Specifically, the proposed rule change would revise Figures 12, 13, and 26 (as renumbered), to correct the label on the x-axis from percentage to bps. In doing so, the proposed rule change would re-scale those figures to reflect the change from percentage to bps. While the change from percentage to bps does not affect the data underlying the figures, the change affects the presentation of these figures because the scale will be larger as 1 bps equals 1/100 of a percentage point.

The proposed rule change would similarly re-scale Figure 5 to make the x-axis bps and would also adjust the bin size of Figure 5, which relates, illustratively, to the thickness of the bars in the figure. The phrase “bin size” in risk data refers to the width of intervals used to group similar data points when analyzing risk. A change in bin size, while not changing the data, can apportion the data more widely or more narrowly across a figure within newly created intervals. As the distributions change, so could the trend lines across the intervals change.

Finally, ICC has corrected certain other deficiencies by updating a footnote to a current link on its website, and in correcting small typographical errors elsewhere in the CRMF.

III. Discussion and Commission Findings

Section 19(b)(2)(C) of the Act requires the Commission to approve a proposed rule change of a self-regulatory organization if it finds that the proposed rule change is consistent with the requirements of the Act and the rules

and regulations thereunder applicable to the organization.⁵ Under the Commission’s Rules of Practice, the “burden to demonstrate that a proposed rule change is consistent with the Exchange Act and the rules and regulations issued thereunder . . . is on the self-regulatory organization [‘SRO’] that proposed the rule change.”⁶

The description of a proposed rule change, its purpose and operation, its effect, and a legal analysis of its consistency with applicable requirements must all be sufficiently detailed and specific to support an affirmative Commission finding,⁷ and any failure of an SRO to provide this information may result in the Commission not having a sufficient basis to make an affirmative finding that a proposed rule change is consistent with the Exchange Act and the applicable rules and regulations.⁸ Moreover, “unquestioning reliance” on an SRO’s representations in a proposed rule change is not sufficient to justify Commission approval of a proposed rule change.⁹

After carefully considering the proposed rule change, the Commission finds that the proposed rule change is consistent with the requirements of the Exchange Act and the rules and regulations thereunder applicable to ICC. More specifically, the Commission finds *that* the proposed rule change is consistent with Section 17A(b)(3)(F) of the Act¹⁰ and Rules 17Ad–22(e)(5) thereunder.¹¹

a. Consistency With Section 17A(b)(3)(F) of the Act

Section 17A(b)(3)(F) of the Act requires, among other things, that the rules of ICC be designed to promote the prompt and accurate clearance and settlement of securities transactions and, to the extent applicable, derivative agreements, contracts, and transactions.¹² Based on the review of the record, and for the reasons described below, ICC’s proposed updates in the manner described above are consistent with the prompt and accurate clearance and settlement of securities transactions, derivatives agreements, contracts, and transactions.

⁵ 15 U.S.C. 78s(b)(2)(C).

⁶ Rule 700(b)(3), Commission Rules of Practice, 17 CFR 201.700(b)(3).

⁷ *Id.*

⁸ *Id.*

⁹ *Susquehanna Int’l Group, LLP v. Securities and Exchange Commission*, 866 F.3d 442, 447 (D.C. Cir. 2017) (“*Susquehanna*”).

¹⁰ 15 U.S.C. 78q–1(b)(3)(F).

¹¹ 17 CFR 240.17Ad–22(e)(5).

¹² 15 U.S.C. 78q–1(b)(3)(F).

The proposed rule change is consistent with Section 17A(b)(3)(F) of the Act because it would clarify the CRMF by eliminating an unnecessary risk measurement. The use of ES as a risk measurement to establish haircut factors for pricing collateral is already a part of ICC’s risk methodology, and ICC has determined that this calculation will always be more conservative than, and thus always used in lieu of, a VaR risk measurement. The confidential risk calculations and data provided by ICC and reviewed by the Commission demonstrate that ES has always been the most conservative methodology for setting collateral haircut factors when compared to VaR and that it is reasonable to expect that, going forward, ES will continue to be the most conservative methodology for setting collateral haircut factors in essentially all circumstances. Therefore, there would be no actual change in the actual haircut calculation when ICC applies its risk methodology after the proposed rule change is effectuated. Removing VaR as a risk measurement would help avoid the impression that ICC uses both VaR and ES, and therefore would make the CRMF clearer and easier to apply in practice.

Having policies and procedures that clearly and accurately document the way ICC measures risk associated with fluctuations of collateral asset prices is an important component to the effectiveness of ICC’s risk management system and supports ICC’s ability to maintain adequate financial resources and collateral management resources. The proposed rule change is, consequently, consistent with the prompt and accurate clearance and settlement of securities transactions, derivatives agreements, contracts, and transactions, within the meaning of Section 17A(b)(3)(F) of the Act.¹³

b. Consistency With Rule 17Ad–22(e)(5) of the Act

Rule 17Ad–22(e)(5) under the Act requires ICC to establish, implement, maintain and enforce written policies and procedures reasonably designed to limit the assets it accepts as collateral to those with low credit, liquidity, and market risks, and set and enforce appropriately conservative haircuts and concentration limits if it requires collateral to manage its or its participants’ credit exposure.¹⁴ Based on the review of the record, and for the reasons described below, ICC’s

¹³ 15 U.S.C. 78q–1(b)(3)(F).

¹⁴ 17 CFR 240.17Ad–22(e)(5).

proposed revisions are consistent with Rule 17Ad–22(e)(5).

As noted above, while ICC's current CRMF indicates that it will use either VaR or ES to establish haircut factors for the purposes of pricing and posting collateral, in practice ES has always produced the more conservative results and therefore ICC has never utilized VaR to set and enforce the haircut factors it uses to price collateral. By removing VaR from CRMF and definitively identifying ES as the exclusive risk methodology that ICC will use to set and enforce the haircut factors it uses to price collateral going forward, the proposed revisions will make the CRMF more clear and transparent as a risk management framework and help facilitate ICC's efficient and effective pricing of Clearing Member collateral. Adjusting the Figures in the CRMF to better illustrate the data used by ICC will likewise enhance the clarity and transparency of ICC's risk methodology, and improve ICC's ability to communicate and explain its risk for establishing haircut factors for the purposes of pricing and posting collateral.

Accordingly, the proposed rule change is consistent with the requirements of Rule 17Ad–22(e)(5) under the Act.¹⁵

IV. Conclusion

On the basis of the foregoing, the Commission finds that the proposed rule change is consistent with the requirements of the Act, and in particular, with the requirements of Section 17A(b)(3)(F)¹⁶ of the Act and Rule 17Ad–22(e)(5) thereunder.¹⁷

It is therefore ordered pursuant to Section 19(b)(2) of the Act¹⁸ that the proposed rule change (SR–ICC–2024–003), be, and hereby is, approved.¹⁹

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.²⁰

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2024–12686 Filed 6–10–24; 8:45 am]

BILLING CODE 8011–01–P

DEPARTMENT OF STATE

[Public Notice: 12414]

Annual Determination and Certification of Shrimp-Harvesting Nations

AGENCY: Bureau of Oceans and International Environmental and Scientific Affairs, State Department.

ACTION: Notice of annual determination and certification.

SUMMARY: On May 23, 2024, the Department of State determined and certified to Congress that wild-caught shrimp harvested in the following nations, particular fisheries of certain nations, and Hong Kong are eligible to enter the United States: Argentina, Australia (Northern Prawn Fishery, the Queensland East Coast Trawl Fishery, the Spencer Gulf, and the Torres Strait Prawn Fishery), the Bahamas, Belgium, Belize, Canada, Chile, Colombia, Costa Rica, Denmark, the Dominican Republic, Ecuador, El Salvador, Estonia, Fiji, France (French Guiana), Gabon, Germany, Guatemala, Guyana, Honduras, Iceland, Ireland, Italy (giant red shrimp), Jamaica, Japan (shrimp baskets in Hokkaido), Republic of Korea (mosquito nets), Mexico, the Netherlands, New Zealand, Nicaragua, Nigeria, Norway, Oman, Panama, Peru, Russia, Spain (Mediterranean red shrimp), Sri Lanka, Suriname, Sweden, the United Kingdom, and Uruguay. For nations, economies, and fisheries not listed above, only shrimp harvested from aquaculture is eligible to enter the United States. All shrimp imports into the United States must be accompanied by the DS–2031 Shrimp Exporter's/Importer's Declaration.

DATES: This determination and certification notice is effective on June 11, 2024.

FOR FURTHER INFORMATION CONTACT:

Jared Milton, Section 609 Program Manager, Office of Marine Conservation, Bureau of Oceans and International Environmental and Scientific Affairs, Department of State, 2201 C Street NW, Washington, DC 20520–2758; telephone: (202) 647–3263; email: DS2031@state.gov.

SUPPLEMENTARY INFORMATION: Section 609 of Public Law 101–162 (“Sec. 609”) prohibits imports of wild-caught shrimp or products from shrimp harvested with commercial fishing technology unless the President certifies to the Congress by May 1, 1991, and annually thereafter, that either: (1) the harvesting nation has adopted a regulatory program governing the incidental taking of relevant species of sea turtles in the course of commercial shrimp harvesting that is

comparable to that of the United States and that the average rate of that incidental taking by the vessels of the harvesting nation is comparable to the average rate of incidental taking of sea turtles by United States vessels in the course of such harvesting; or (2) the particular fishing environment of the harvesting nation does not pose a threat of the incidental taking of sea turtles in the course of shrimp harvesting. The President has delegated the authority to make this certification to the Secretary of State (“Secretary”) who further delegated the authority within the Department of State (“Department”). The Revised Guidelines for the Implementation of Sec. 609 were published in the **Federal Register** on July 8, 1999, at 64 FR 36946.

On May 23, 2024, the Department certified to Congress the following nations pursuant to section 609(b)(2)(A) and (B) on the basis that they have adopted a regulatory program governing the incidental taking of relevant species of sea turtles in the course of commercial shrimp harvesting that is comparable to that of the United States and that the average rate of that incidental taking by the vessels of the harvesting nation is comparable to the average rate of incidental taking of such sea turtles by United States vessels in the course of such harvesting: Colombia, Ecuador, El Salvador, Gabon, Guatemala, Guyana, Honduras, Mexico, Nicaragua, Nigeria, Panama, and Suriname. The Department also certified pursuant to section 609(b)(2)(C) several shrimp-harvesting nations and one economy as having fishing environments that do not pose a threat to sea turtles, including the following nations with shrimping grounds only in cold waters where the risk of taking sea turtles is negligible: Argentina, Belgium, Canada, Chile, Denmark, Estonia, Germany, Iceland, Ireland, the Netherlands, New Zealand, Norway, Russia, Sweden, the United Kingdom, and Uruguay. Additionally, the Department certified pursuant to section 609(b)(2)(C) that the following nations and Hong Kong only harvest shrimp using small boats with crews of less than five that only use manual rather than mechanical means to retrieve nets or catch shrimp using other methods that do not pose a threat of incidental taking of sea turtles: the Bahamas, Belize, Costa Rica, the Dominican Republic, Fiji, Jamaica, Oman, Peru, and Sri Lanka.

The Department has certified the above listed nations and Hong Kong pursuant to Sec. 609, and shrimp and products from shrimp are eligible for importation into the United States

¹⁵ 17 CFR 240.17Ad–22(e)(5).

¹⁶ 15 U.S.C. 78q–1(b)(3)(F).

¹⁷ 17 CFR 240.17Ad–22(e)(5).

¹⁸ 15 U.S.C. 78s(b)(2).

¹⁹ In approving the proposed rule change, the Commission considered the proposal's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

²⁰ 17 CFR 200.30–3(a)(12).

utilizing the Shrimp Exporter's/Importer's Declaration ("DS-2031") Box 7(B) provision for shrimp "harvested in the waters of a nation currently certified pursuant to Section 609 of Pubic Law 101-162."

Shrimp and products of shrimp harvested with turtle excluder devices ("TEDs") in an uncertified nation may, under specific circumstances, be eligible for importation into the United States under the DS-2031 Box 7(A)(2) provision for shrimp "harvested using TEDs comparable in effectiveness to those in the United States, as determined by the U.S. Department of State." Use of this provision requires that the Secretary or his or her delegate determine in advance that the government of the harvesting nation has put in place adequate procedures to monitor the use of TEDs in the specific fishery in question and to ensure the accurate completion of the DS-2031 forms. At this time, the Department has determined that only shrimp and products from shrimp harvested in the Northern Prawn Fishery, the Queensland East Coast Trawl Fishery, and the Torres Strait Prawn Fishery in Australia, and in the French Guiana domestic trawl fishery of France are eligible for entry under this provision. A responsible government official of Australia or France must sign in Block 8 of the DS-2031 form accompanying these imports into the United States.

In addition, shrimp and products of shrimp harvested in a manner or under circumstances determined by the Department of State not to pose a threat of the incidental taking of sea turtles may, under specific circumstances, be eligible for importation into the United States under the DS-2031 Box 7(A)(4) provision for shrimp "harvested in a manner or under circumstances not to pose a threat of the incidental taking of sea turtles, as determined by the U.S. Department of State." The Department has determined that shrimp and products from shrimp harvested in the Spencer Gulf region in Australia, with shrimp baskets in Hokkaido, Japan, with "mosquito" nets in the Republic of Korea, Mediterranean red shrimp (*Aristeus antennatus*) and products from that shrimp harvested in the Mediterranean Sea in Spain, and giant red shrimp (*Aristaeomorpha foliacea*) and products from that shrimp harvested in Italy may be imported into the United States under the DS-2031 Box 7(A)(4) provision. A responsible government official of Australia, Japan, the Republic of Korea, Spain, or Italy must sign in Block 8 of the DS-2031 form accompanying these imports into the United States.

A completed DS-2031 Shrimp Exporter's/Importer's Declaration must accompany all imports of shrimp and products from shrimp into the United States. The DS-2031 form was recently revised, and the current version is accessible at the following link: <https://eforms.state.gov/Forms/ds2031.PDF>. Importers of shrimp and products from shrimp harvested in certified nations and Hong Kong must either provide the DS-2031 form to Customs and Border Protection at the port of entry or provide the information required by the DS-2031 through the Automated Commercial Environment. Importers of shrimp and products from shrimp from certified nations and Hong Kong should mark the box 7(B) provision for shrimp "harvested in the waters of a nation currently certified pursuant to Section 609 of P.L. 101-162" regardless of whether the shrimp is wild-caught or the product of aquaculture. DS-2031 forms accompanying all imports of shrimp and products from shrimp harvested in uncertified nations and economies, to include all fisheries with determinations, must be originals with Box 7(A)(1), 7(A)(2), or 7(A)(4) checked, consistent with the form's instructions with regard to the method of harvest of the shrimp and based on any relevant prior determinations by the Department, and signed by a responsible government official of the harvesting nation. The Department did not determine that shrimp or products from shrimp harvested in a manner as described in 7(A)(3) in any uncertified nation or economy is eligible to enter the United States. The importation of wild-caught shrimp or products from that shrimp from any nation or fishery without a certification or determination will not be allowed.

The Department has communicated these certifications and determinations under Sec. 609 to the Offices of Field Operations and of Trade at U.S. Customs and Border Protection.

David F. Hogan,

*Director, Office of Marine Conservation,
Department of State.*

[FR Doc. 2024-12763 Filed 6-10-24; 8:45 am]

BILLING CODE 4710-09-P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

[Docket No. 2013-0259]

Agency Information Collection Activities: Requests for Comments; Clearance of Renewed Approval of Information Collection: Advisory Circular: Reporting of Laser Illumination of Aircraft

AGENCY: Federal Aviation Administration (FAA), Department of Transportation (DOT).

ACTION: Notice and request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, FAA invites public comments about our intention to request the Office of Management and Budget (OMB) approval renew information collection. The **Federal Register** Notice with a 60-day comment period soliciting comments on the following collection of information was published on August 17, 2023. The collection involves information to be collected will be used to and/or is necessary because Advisory Circular 70-2B provides guidance to civilian air crews on the reporting of laser illumination incidents and recommended mitigation actions to be taken in order to ensure continued safe and orderly flight operations.

DATES: Written comments should be submitted by July 6, 2024.

ADDRESSES: Please send written comments:

By Electronic Docket:
www.regulations.gov (Enter docket number into search field).

By Mail: Nicholas Torgerson, Federal Aviation Administration, AJR-223, 800 Independence Ave. SW, Washington, DC 20591.

FOR FURTHER INFORMATION CONTACT: Nicholas Torgerson, by email at: Nicholas.d.torgerson@faa.gov; phone: 202-322-4157.

SUPPLEMENTARY INFORMATION:

Public Comments Invited: You are asked to comment on any aspect of this information collection, including (a) Whether the proposed collection of information is necessary for FAA's performance; (b) the accuracy of the estimated burden; (c) ways for FAA to enhance the quality, utility and clarity of the information collection; and (d) ways that the burden could be minimized 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.

OMB Control Number: 2120–0698.

Title: Advisory Circular (AC):
Reporting of Laser Illumination of
Aircraft.

Form Numbers: Advisory Circular 70–
2B, Reporting of Laser Illumination of
Aircraft.

Type of Review: Renewal of an
information collection.

Background: The **Federal Register**
Notice with a 60-day comment period
soliciting comments on the following
collection of information was published
on August 17, 2023 (88 FR 58633).
Advisory Circular 70–2B provides
guidance to civilian air crews on the
reporting of laser illumination incidents
and recommended mitigation actions to
be taken in order to ensure continued
safe and orderly flight operations.
Information is collected from pilots and
aircrews that are affected by an
unauthorized illumination by lasers.
The requested reporting involves an
immediate broadcast notification to Air
Traffic Control (ATC) when the incident
occurs, as well as a broadcast warning
of the incident if the aircrew is flying in
uncontrolled airspace. In addition, the
AC requests that the aircrew supply a
written report of the incident and send
it by fax or email to the Washington
Operations Control Complex (WOCC) as
soon as possible.

Respondents: Approximately 2,339
pilots and crewmembers.

Frequency: Information is collected
on occasion.

Estimated Average Burden per
Response: 10 minutes.

Estimated Total Annual Burden: 220
hours.

Issued in Washington, DC, on June 6, 2024.

Sandra L. Ray,

Aviation Safety Inspector, AFS–260.

[FR Doc. 2024–12703 Filed 6–10–24; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Staffing-Related Relief Concerning Operations at Ronald Reagan Washington National Airport, John F. Kennedy International Airport, LaGuardia Airport, and Newark Liberty International Airport, October 27, 2024, Through March 29, 2025 (Winter 2024/ 2025) and March 30, 2025, Through October 25, 2025 (Summer 2025)

AGENCY: Department of Transportation,
Federal Aviation Administration (FAA).

ACTION: Extension to limited waiver of
the slot usage requirement.

SUMMARY: This action extends the
Staffing-Related Relief Concerning

Operations at Ronald Reagan
Washington National Airport, John F.
Kennedy International Airport,
LaGuardia Airport, and Newark Liberty
International Airport, published on
September 20, 2023, from October 27,
2024, through March 29, 2025 (Winter
2024/2025) and March 30, 2025,
through October 25, 2025 (Summer
2025). The limited waiver remains
effective until October 25, 2025, and
does not apply to any slots granted by
the Department of Transportation
pursuant to section 505 of the FAA
Reauthorization Act of 2024.

DATES: This action is applicable on
October 27, 2024.

ADDRESSES: Requests may be submitted
by mail to Slot Administration Office,
System Operations Services, AJR–0,
Room 300W, 800 Independence Avenue
SW, Washington, DC 20591, or by email
to: 7-awa-slotadmin@faa.gov.

FOR FURTHER INFORMATION CONTACT: Al
Meilus, Slot Administration and
Capacity Analysis, FAA ATO System
Operations Services, AJR–G5, Federal
Aviation Administration, 800
Independence Avenue SW, Washington,
DC 20591; telephone (202) 267–2822;
email al.meilus@faa.gov.

SUPPLEMENTARY INFORMATION:

Background

The New York Terminal Radar
Approach Control facility (N90)
currently provides Air Traffic Control
(ATC) services to overhead flights in the
Northeast corridor and to the New York
City area airports, including John F.
Kennedy International Airport (JFK),
LaGuardia Airport (LGA), and Newark
Liberty International Airport (EWR).
The airspace complexity resulting from
the close proximity of the major
commercial airports serving the New
York City region is a significant
contributing factor to delays at JFK,
LGA, and EWR. Against this challenging
backdrop, N90 continues to face staffing
shortfalls that are impacting ATC's
ability to efficiently manage the volume
of air traffic in this congested airspace
despite best efforts to resolve staffing
shortfalls.

The FAA has made significant
changes to increase N90 staffing through
a combination of incentive and training
programs, as well as by relocating
control of the EWR area from N90 to the
Philadelphia Terminal Radar Approach
Control (PHL) beginning in late July of
this year to relieve N90 staffing
pressures. The FAA has determined N90
will need to reach at least 70% of its
targeted number of onboard Certified
Professional Controllers (CPCs) before
ATC can efficiently manage the full

capacity of the New York airspace that
was in place prior to May 15, 2023. The
operational impact of changes to
address N90 staffing shortages will not
be realized immediately but do chart a
path to mitigating the impact in the next
18–24 months.

The targeted staffing number at N90 is
226 CPCs; the current CPC onboard
number at N90 is 135 (59.7% staffed).
CPCs at N90 presently are divided
between five different areas: EWR, Long
Island MacArthur Airport (ISP), JFK,
LGA and the Liberty area. The N90 EWR
area currently has 33 CPCs; 24 of the 33
EWR area CPCs will be transferred to
PHL in July, the remaining 9 EWR CPCs
will be reassigned to the other
remaining areas in N90. Transferring
control of the EWR area to PHL and
adding 9 CPCs to the remaining N90
areas will result in an estimated staffing
level of 68% of the targeted number of
onboard CPCs at the areas remaining in
N90 by the end of 2025. Control of EWR
area will remain at PHL; however, of the
24 CPCs transferred to PHL, 18 are
planned to return to N90 at the end of
July 2026 and will be redistributed to
the remaining N90 areas. The FAA
estimates that the collective
redistribution of 27 former EWR CPCs to
the other areas of N90, along with the
removal of EWR area servicing
responsibilities, should result in N90
exceeding the 70% mark by the
conclusion of 2026. At PHL, actions are
currently underway to start CPC trainees
to service the EWR area and replace the
18 EWR area CPCs that will return to
N90 at the end of July 2026. Unlike N90,
there is a robust pipeline of experienced
controllers interested in transferring to
PHL. This pipeline of personnel will
allow the FAA to build up CPC staffing
for the EWR area at PHL more quickly
than has been experienced at N90.
Regardless, the FAA will continue to
invest in staffing at N90 to meet
anticipated future needs.

With ever-growing demand for air
travel in the New York City region,
additional measures are necessary to
ensure the FAA is able to provide
expeditious services to aircraft operators
and their passengers that traverse this
airspace. Early discussions with carriers
indicate an interest in increasing
operations after October 27, 2024,
through most of the Winter 2024/2025
scheduling season and for all of the
Summer 2025 scheduling season. This
being the case, the FAA expects
increased delays and cancellations in
the New York region to exceed those
experienced over Summer 2022 and
Winter 2022/2023¹ if a waiver similar to

¹ Refer to "Analysis" section for delay analysis.

the one that has been in effect for the Summer 2023, Winter 2023/2024, and Summer 2024 season is not in place for the Winter 2024/2025 and Summer 2025 scheduling season to allow carriers to reduce schedules without penalties for non-use of slots or previously approved operating times. Reducing schedules will improve the alignment between scheduled operations and actual operations, will help prevent unnecessary delays, will help optimize the efficient use of the airports' resources, and will help deliver passengers to their destinations more reliably and on time.

Summary of Petitions Received

On April 3, 2024, Airlines for America (A4A) submitted a petition of behalf of its member carriers² requesting an extension of the current relief provided by FAA due to post-pandemic effects on ATC staffing at N90 through the end of the Summer 2025 season. A4A asserts that the current slot waiver successfully created a better travel experience for consumers and that the underlying conditions creating the need for a waiver still exist as staffing shortages persist. In addition, A4A requests that FAA restore carriers' ability to request retroactive relief if the impacts of controller staffing shortages are even more severe than anticipated and that the FAA not reallocate returned slots for ad-hoc use during the waiver period. Finally, A4A requests that FAA make a timely decision regarding relief as time is needed to give carriers stability and the ability to plan.

On April 5, 2024, the International Air Transport Association (IATA) submitted a petition on behalf of its member carriers³ in support of A4A's request for an extension of the current slot relief through the end of the Summer 2025 season and other relief to protect the traveling public from operational disruptions. IATA asserts that the current relief allowed for careful planning by airlines and resulted in a notably better travel experience for consumers. IATA requests that FAA grant this relief by May 1, 2024, so that carriers can make the complex aircraft

and human capital decisions necessary to serve the flying public.

On April 19, 2024, the Airports Council International of North America (ACI-NA) submitted a petition on behalf of its member airports⁴ opposing A4A's request for an extension of the current slot relief. ACI-NA asserts that there is no proven correlation between the slot relief and ATC capacity shortage and that slot usage waivers in general only serve to protect market access for incumbents. It seeks information surrounding and supporting the decision to grant slot relief for impacted New York airports and requests the FAA to provide an opportunity to the public to comment on A4A's request for relief.

Standard

At JFK and LGA, slot-holding carriers must use each assigned slot at least 80 percent of the time.⁵ The FAA will withdraw slots not meeting the minimum usage requirements. The FAA may waive the 80 percent usage requirement in the event of a highly unusual and unpredictable condition that is beyond the control of the slot-holding air carrier, and which affects carrier operations for a period of five consecutive days or more.⁶

At Ronald Reagan Washington National Airport (DCA), the FAA also will recall any slot not used at least 80 percent of the time over a two-month period.⁷ The FAA may waive this minimum usage requirement in the event of a highly unusual and unpredictable condition that is beyond the control of the slot-holding carrier, and which exists for a period of nine or more days.⁸

In determining historical rights to allocated slots, including whether to grant a waiver of the usage requirement, the FAA seeks to ensure the efficient use of valuable aviation infrastructure and maximize the benefits to both airport users and the traveling public.

⁴ ACI-NA is an organization representing local, regional, and state governing bodies that own and operate more than 300 airports operating in the United States; and nearly 400 aviation-related businesses. The ACI-NA Slot Task Force comprises all Level 2 and Level 3 airports in the United States.

⁵ Operating Limitations at John F. Kennedy International Airport, 89 FR 41486 (May 13, 2024); Operating Limitations at New York LaGuardia Airport, 89 FR 41484 (May 13, 2024).

⁶ At JFK, the FAA will determine historical rights to operating authorizations and withdrawal of those rights due to insufficient usage on a seasonal basis and in accordance with the schedule approved by the FAA prior to the commencement of the applicable season. See JFK Order, 89 FR at 41488. At LGA, the FAA will withdraw any operating authorization not used at least 80 percent of the time over a two-month period. See LGA Order, 89 FR at 41485.

⁷ See 14 CFR 93.227(a).

⁸ See 14 CFR 93.227(j).

The minimum usage requirement is expected to accommodate routine cancellations under all but the most unusual circumstances. Carriers proceed at their own risk if they make scheduling decisions in anticipation of the FAA granting a slot usage waiver.

Analysis

The number of certified controllers at N90 is still not sufficient to allow the FAA to handle normal traffic levels. The FAA has worked with NATCA on a long-term solution to solve the chronic low levels of fully certified air traffic controllers at that facility through a combination of incentive and training programs, as well as relocating control of the EWR area to PHL. The FAA will continue to partner with NATCA as it continues efforts to remediate ATC staffing shortages at N90.

Due to the volume of originating and destination flights in the New York City region, as well as the interdependency and complexity of the airspace surrounding JFK, LGA, and EWR, delays caused in part by N90 staffing shortfalls are expected to significantly impact carriers' ability to operate and meet minimum usage requirements in the Winter 2024/2025 and Summer 2025 scheduling seasons. Absent increased flexibility, the FAA anticipates a high likelihood of congestion, delay, and cancellations at JFK, LGA, and EWR.

Typically, the 20 percent non-utilization allowed under the minimum usage requirement accounts for cancellations due to ATC staffing delays; however, the extent of N90 staffing shortfalls and the expected numbers of scheduled operations for the Winter 2024/2025 and Summer 2025 scheduling seasons present a highly unusual and unpredictable condition beyond the control of carriers that will impact operations through the entire Winter 2024/2025 and Summer 2025 scheduling seasons.

Using the Annual Service Volume (ASV) model,⁹ the FAA projected the delay the NYC airports would experience in the absence of a waiver for Summer 2024.¹⁰ Using Summer

⁹ FAA-developed modeling suite of tools for conducting operational impact analysis for airports and to establish the annual service volume for airports. ASV simulations relate total annual operations to a target delay value and are used by FAA in reports to Congress that identify the airports projected to constrain the NAS. See https://www.faa.gov/about/office_org/headquarters_offices/ato/service_units/systemops/perf_analysis/sim_tools.

¹⁰ The FAA projected a Summer 2024 scenario because the FAA has already received the air carrier schedules for the Summer 2024 scheduling season, and demand is not likely to decrease in 2025.

² A4A members are Alaska Air Group, Inc.; American Airlines Group, Inc.; Atlas Air Worldwide Holdings, Inc.; Delta Air Lines, Inc.; FedEx Corp.; Hawaiian Airlines; JetBlue Airways Corp.; Southwest Airlines Co.; United Airlines Holdings, Inc.; and United Parcel Service Co. Air Canada is an associate member. Alaska Airlines did not join in the submission of A4A's letter.

³ IATA is the trade association of the world's airlines, comprising some 320 member airlines in more than 120 countries and representing approximately 83 percent of the world's total air traffic.

2022 data¹¹ as baseline comparison, the FAA estimates Summer 2024 would experience increased operations by 8.8% to 11%,¹² which would result in 2.3 to 2.8 million minutes of additional delay, or 53% to 65% additional delay, compared to the delay experienced in Summer 2022. At a minimum, the FAA expects these delay numbers to remain valid through Summer 2025.

Therefore, a waiver of minimum slot usage requirements at JFK and LGA, and a similar policy of prioritizing returned operations at EWR, through October 25, 2025, is necessary to allow carriers to reduce operations to enable scheduling and operational stability for the benefit of the flying public.

In addition, because New York City-DCA is a high-frequency market for multiple carriers, the FAA recognizes this market is a likely target for carriers to consolidate flights while retaining their network connectivity. If carriers choose to reduce their schedules in the New York City-DCA market, the FAA encourages, to the extent practical, carriers to utilize their DCA slots to operate to other destinations. However, if carriers choose not to utilize their DCA slots elsewhere, the FAA may consider providing relief to DCA slots that are impacted by the reduction in operations at the New York City airports, except that the limited waiver of the minimum slot usage requirements is not available for any slots granted by the DOT pursuant to section 505 of the FAA Reauthorization Act of 2024 (Pub. L. 118–63).

Carriers have the ability to request retroactive relief; however, they should be aware that the N90 staffing shortfalls will not likely form a sufficient basis for further relief going forward in the Winter 2024/2025 and Summer 2025 scheduling seasons because carriers will have had sufficient opportunity to plan and take remedial action under this waiver policy. The FAA does not foresee providing additional post-hoc relief associated with ATC staffing given the extraordinary relief provided here. Given this relief, operational impacts associated with N90 staffing during the Winter 2024/2025 and Summer 2025 scheduling season will likely not have been beyond carriers' control and will

not serve as a justification for a separate waiver.

Decision

The FAA determined that the post-pandemic effects on N90 staffing meet the applicable waiver standards and warrant a limited waiver of minimum slot usage requirements at JFK and LGA to allow carriers to return up to ten percent of their slots at each airport, as well as impacted operations between DCA and the New York City airports. In addition, the FAA has determined the post-pandemic effects on N90 staffing warrant a limited policy for prioritizing returned operations at EWR to allow carriers to return up to ten percent of their approved operating timings, for purposes of establishing a carrier's operational baseline in the next corresponding season. Despite staffing projections indicating N90 will not reach 70% of the targeted staffing level until the conclusion of 2026, the FAA is taking a measured approach and providing relief in this waiver notice only until the end of the Summer 2025 scheduling season. The FAA will re-evaluate the staffing levels at N90 and the impact to operations in the New York City area before deciding if a waiver beyond the Summer 2025 scheduling season is necessary. Carriers seeking to return their slots and approved operating timings must do so by August 15, 2024, for the Winter 2024/2025 scheduling season (October 27, 2024, through March 29, 2025); and by January 15, 2025, for the Summer 2025 scheduling season (March 30, 2025, through October 25, 2025) to be eligible for relief under this waiver. For DCA, this relief is available only for flights impacted by operations to or from the New York City area airports. If carriers utilizing the relief provided under this limited waiver at EWR subsequently operate unapproved flights at that airport, those carriers will forfeit their scheduling preference to an equal number of returned, approved operating timings chosen at the FAA's discretion for the subsequent equivalent traffic season. Furthermore, the FAA expects carriers to up-gauge aircraft serving the affected airports to the extent possible to maintain passenger throughput and minimize the impact on consumers. The FAA also expects carriers to maintain connections between the affected airports and regional airports to the extent possible in support of continuous scheduled interstate air transportation for small communities and isolated areas. The FAA will closely coordinate with the Department of Transportation, which will be monitoring for indications of

unfair, deceptive, or anticompetitive practices or other unlawful economic activity associated with or resulting from the relief granted by this notice. In addition, the FAA expects carriers to return scheduled operations in the peak delay periods of the day. The following hours (in local time) are the most prone to delay at each airport: EWR: 1400–2159, JFK: 1300–2259, LGA: 1300–2159.

The FAA will not reallocate the temporarily returned slots or approved operating timings at JFK, LGA, or EWR, as the goal is to reduce the total volume of operations in the New York City region. Carriers are encouraged to utilize their DCA slots in other markets before returning them to the FAA. In the event DCA slots are returned under this waiver, other carriers will have an opportunity to operate the slots on an *ad hoc* basis without historic precedence.

The FAA will treat as used the specific slots returned in accordance with the conditions in this notice for the period from October 27, 2024, through March 29, 2025 (Winter 2024/2025) and March 30, 2025, through October 25, 2025 (Summer 2025).

The relief is subject to the following conditions:

1. The specific slots and approved operating timings must be returned to the FAA by August 15, 2024, for the Winter 2024/2025 scheduling season; and by January 15, 2025, for the Summer 2025 scheduling season.
2. This waiver applies only to slots that have corresponding, scheduled operations during the period of the grant. A carrier temporarily returning a slot or approved operating time to the FAA for relief under this waiver must identify corresponding scheduled operations for Winter 2024/2025, or approved slots or operating timings for Summer 2025. The FAA may validate information against published schedule data prior to the issuance of this notice, and other operational data maintained by FAA. Slots or operating times returned without an associated scheduled and canceled operation will not receive relief.
3. Slots or approved operating timings newly allocated for initial use since the previous corresponding scheduling season are not eligible for relief.
4. Slots authorized at DCA by Department of Transportation or FAA exemptions are not eligible for relief.
5. Carriers must not engage in unfair, deceptive, or anticompetitive practices regarding their slot usage, leasing agreements, or operations associated with the relief provided by this notice.

¹¹ Summer 2022 data is used as baseline for comparison because this was the last summer scheduling season unaffected by the ATC waivers.

¹² Under the current waiver, carriers returned 9% of their initially submitted schedules. Compared to Summer 2023, scheduled operations in Summer 2024 increased by 2%. If the FAA assumes an 80% actual usage rate, that results in 8.8% (that is, $((0.09 + 0.02) \times 0.8 = 0.088)$ increase of actual operations. If the FAA assumes 100% actual usage rate, then that would be an 11% $(0.09 + 0.02)$ increase.

Issued in Washington, DC, on June 5, 2024.

Marc A. Nichols,

Chief Counsel.

Alyce Hood-Fleming,

Vice President, System Operations Services.

[FR Doc. 2024–12690 Filed 6–10–24; 8:45 am]

BILLING CODE P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA–2013–0123; FMCSA–2013–0125; FMCSA–2013–0126; FMCSA–2014–0102; FMCSA–2014–0107; FMCSA–2015–0327; FMCSA–2015–0328; FMCSA–2015–0329; FMCSA–2017–0057; FMCSA–2017–0059; FMCSA–2017–0060; FMCSA–2018–0139; FMCSA–2019–0109; FMCSA–2019–0110; FMCSA–2020–0024; FMCSA–2020–0025; FMCSA–2022–0032; or FMCSA–2022–0033]

Qualification of Drivers; Exemption Applications; Hearing

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of renewal of exemptions; request for comments.

SUMMARY: FMCSA announces its decision to renew exemptions for 34 individuals from the hearing requirement in the Federal Motor Carrier Safety Regulations (FMCSRs) for interstate commercial motor vehicle (CMV) drivers. The exemptions enable these hard of hearing and deaf individuals to continue to operate CMVs in interstate commerce.

DATES: Each group of renewed exemptions were applicable on the dates stated in the discussions below and will expire on the dates provided below. Comments must be received on or before July 11, 2024.

ADDRESSES: You may submit comments identified by the Federal Docket Management System Docket No. FMCSA–2013–0123, Docket No. FMCSA–2013–0125, Docket No. FMCSA–2013–0126, Docket No. FMCSA–2014–0102, Docket No. FMCSA–2014–0107, Docket No. FMCSA–2015–0327, Docket No. FMCSA–2015–0328, Docket No. FMCSA–2015–0329, Docket No. FMCSA–2017–0057, Docket No. FMCSA–2017–0059, Docket No. FMCSA–2017–0060, Docket No. FMCSA–2018–0139, Docket No. FMCSA–2019–0109, Docket No. FMCSA–2019–0110, Docket No. FMCSA–2020–0024, Docket No. FMCSA–2020–0025, Docket No. FMCSA–2022–0032, or Docket No.

FMCSA–2022–0033 using any of the following methods:

- *Federal eRulemaking Portal:* Go to www.regulations.gov/, insert the docket number (FMCSA–2013–0123, FMCSA–2013–0125, FMCSA–2013–0126, FMCSA–2014–0102, FMCSA–2014–0107, FMCSA–2015–0327, FMCSA–2015–0328, FMCSA–2015–0329, FMCSA–2017–0057, FMCSA–2017–0059, FMCSA–2017–0060, FMCSA–2018–0139, FMCSA–2019–0109, FMCSA–2019–0110, FMCSA–2020–0024, FMCSA–2020–0025, FMCSA–2022–0032, or FMCSA–2022–0033) in the keyword box and click “Search.” Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, and click on the “Comment” button. Follow the online instructions for submitting comments.

- *Mail:* Dockets Operations; U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building Ground Floor, Washington, DC 20590–0001.

- *Hand Delivery:* West Building Ground Floor, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, between 9 a.m. and 5 p.m. ET Monday through Friday, except Federal Holidays.

- *Fax:* (202) 493–2251.

To avoid duplication, please use only one of these four methods. See the “Public Participation” portion of the **SUPPLEMENTARY INFORMATION** section for instructions on submitting comments.

FOR FURTHER INFORMATION CONTACT: Ms. Christine A. Hydock, Chief, Medical Programs Division, FMCSA, DOT, 1200 New Jersey Avenue SE, Room W64–224, Washington, DC 20590–0001, (202) 366–4001, fmcamedical@dot.gov. Office hours are 8:30 a.m. to 5 p.m. ET Monday through Friday, except Federal holidays. If you have questions regarding viewing or submitting material to the docket, contact Dockets Operations, (202) 366–9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation

A. Submitting Comments

If you submit a comment, please include the docket number for this notice (Docket No. FMCSA–2013–0123, Docket No. FMCSA–2013–0125, Docket No. FMCSA–2013–0126, Docket No. FMCSA–2014–0102, Docket No. FMCSA–2014–0107, Docket No. FMCSA–2015–0327, Docket No. FMCSA–2015–0328, Docket No. FMCSA–2015–0329, Docket No. FMCSA–2017–0057, Docket No. FMCSA–2017–0059, Docket No. FMCSA–2017–0060, Docket No. FMCSA–2018–0139, Docket No.

FMCSA–2019–0109, Docket No. FMCSA–2019–0110, Docket No. FMCSA–2020–0024, Docket No. FMCSA–2020–0025, Docket No. FMCSA–2022–0032, or Docket No. FMCSA–2022–0033), indicate the specific section of this document to which each comment applies, and provide a reason for each suggestion or recommendation. You may submit your comments and material online or by fax, mail, or hand delivery, but please use only one of these means. FMCSA recommends that you include your name and a mailing address, an email address, or a phone number in the body of your document so that FMCSA can contact you if there are questions regarding your submission.

To submit your comment online, go to www.regulations.gov/, insert the docket number (FMCSA–2013–0123, FMCSA–2013–0125, FMCSA–2013–0126, FMCSA–2014–0102, FMCSA–2014–0107, FMCSA–2015–0327, FMCSA–2015–0328, FMCSA–2015–0329, FMCSA–2017–0057, FMCSA–2017–0059, FMCSA–2017–0060, FMCSA–2018–0139, FMCSA–2019–0109, FMCSA–2019–0110, FMCSA–2020–0024, FMCSA–2020–0025, FMCSA–2022–0032, or FMCSA–2022–0033) in the keyword box and click “Search.” Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, click the “Comment” button, and type your comment into the text box on the following screen. Choose whether you are submitting your comment as an individual or on behalf of a third party and then submit.

If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. FMCSA will consider all comments and material received during the comment period.

B. Viewing Comments

To view comments go to www.regulations.gov. Insert the docket number (FMCSA–2013–0123, FMCSA–2013–0125, FMCSA–2013–0126, FMCSA–2014–0102, FMCSA–2014–0107, FMCSA–2015–0327, FMCSA–2015–0328, FMCSA–2015–0329, FMCSA–2017–0057, FMCSA–2017–0059, FMCSA–2017–0060, FMCSA–2018–0139, FMCSA–2019–0109, FMCSA–2019–0110, FMCSA–2020–0024, FMCSA–2020–0025, FMCSA–2022–0032, or FMCSA–2022–0033) in the keyword box and click “Search.” Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, and click “Browse Comments.” 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 20590-0001, 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.

C. Privacy Act

In accordance with 49 U.S.C. 31315(b)(6), DOT solicits comments from the public on the exemption requests. 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 (Federal Docket Management System), which can be reviewed at <https://www.transportation.gov/individuals/privacy/privacy-act-system-records-notices>, the comments are searchable by the name of the submitter.

II. Background

Under 49 U.S.C. 31136(e) and 31315(b), FMCSA may grant an exemption from the FMCSRs for no longer than a 5-year period if it finds such exemption would likely achieve a level of safety that is equivalent to, or greater than, the level that would be achieved absent such exemption. The statutes also allow the Agency to renew exemptions at the end of the 5-year period. FMCSA grants medical exemptions from the FMCSRs for a 2-year period to align with the maximum duration of a driver's medical certification.

The physical qualification standard for drivers regarding hearing found in 49 CFR 391.41(b)(11) states that a person is physically qualified to drive a CMV if that person first perceives a forced whispered voice in the better ear at not less than 5 feet with or without the use of a hearing aid or, if tested by use of an audiometric device, does not have an average hearing loss in the better ear greater than 40 decibels at 500 Hz, 1,000 Hz, and 2,000 Hz with or without a hearing aid when the audiometric device is calibrated to American National Standard (formerly ASA Standard) Z24.5-1951.

This standard was adopted in 1970 and was revised in 1971 to allow drivers to be qualified under this standard while wearing a hearing aid, (35 FR 6458, 6463 (Apr. 22, 1970) and 36 FR 12857 (July 8, 1971), respectively).

The 34 individuals listed in this notice have requested renewal of their exemptions from the hearing standard in § 391.41(b)(11), in accordance with FMCSA procedures. Accordingly,

FMCSA has evaluated these applications for renewal on their merits and decided to extend each exemption for a renewable 2-year period.

III. Request for Comments

Interested parties or organizations possessing information that would otherwise show that any, or all, of these drivers are not currently achieving the statutory level of safety should immediately notify FMCSA. The Agency will evaluate any adverse evidence submitted and, if safety is being compromised or if continuation of the exemption would not be consistent with the goals and objectives of 49 U.S.C. 31136(e) and 31315(b), FMCSA will take immediate steps to revoke the exemption of a driver.

IV. Basis for Renewing Exemptions

In accordance with 49 U.S.C. 31136(e) and 31315(b), each of the 34 applicants has satisfied the renewal conditions for obtaining an exemption from the hearing requirement. The 34 drivers in this notice remain in good standing with the Agency. In addition, for commercial driver's license (CDL) holders, the Commercial Driver's License Information System and the Motor Carrier Management Information System are searched for crash and violation data. For non-CDL holders, the Agency reviews the driving records from the State Driver's Licensing Agency. These factors provide an adequate basis for predicting each driver's ability to continue to safely operate a CMV in interstate commerce. Therefore, FMCSA concludes that extending the exemption for each of these drivers for a period of 2 years is likely to achieve a level of safety equal to that existing without the exemption.

In accordance with 49 U.S.C. 31136(e) and 31315(b), the following groups of drivers received renewed exemptions in the month of June and are discussed below. As of June 3, 2024, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following nine individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers:

Carlos Arellano (CA)
Michael Beam (MI)
Arthur Brown (FL)
Gregory Crane (AZ)
Gabriel Garza (TX)
Scott Gentry (FL)
Michael Quinonez (NM)
Robert Rollins (NC)
Roderick Thomas (GA)

The drivers were included in docket number FMCSA-2017-0057, FMCSA-

2019-0110, FMCSA-2013-0126, FMCSA-2022-0032, or FMCSA-2022-0033. Their exemptions are applicable as of June 3, 2024 and will expire on June 3, 2026.

As of June 17, 2024, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following 15 individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers:

Paul Aseka (TX)
Forrest Carroll (OH)
Glenn Ferguson (TX)
Ariel Gonzalez (RI)
Richard Hadlock (IL)
Jesus Javier (NJ)
Yoel Lopez-Perez (FL)
Darren Nordquist (WI)
Anthony Panto (NJ)
Ernest Pratt (PA)
William Symonds (IL)
Steven Tipton (IA)
Daniel Tricolici (MA)
Fernando Velasquez (TX)
Scott Weeaks (OK)

The drivers were included in docket number FMCSA-2013-0123, FMCSA-2013-0125, FMCSA-2014-0107, FMCSA-2015-0327, FMCSA-2015-0328, FMCSA-2015-0329, FMCSA-2017-0059, FMCSA-2018-0139, FMCSA-2019-0109, or FMCSA-2020-0024. Their exemptions are applicable as of June 17, 2024 and will expire on June 17, 2026.

As of June 18, 2024, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following five individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers:

Joshua Affholter (MI)
Gantugla Badarch (IL)
Awash Demoz (MD)
Charles O'Bryan (NY)
Kyle Taylor (GA)

The drivers were included in docket number FMCSA-2020-0025. Their exemptions are applicable as of June 18, 2024 and will expire on June 18, 2026.

As of June 25, 2024, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following three individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers:

Alfredo Ramirez (TX); Julie Ramirez (TX); and Hayden Teesdale (TX).

The drivers were included in docket number FMCSA-2014-0102. Their exemptions are applicable as of June 25, 2024 and will expire on June 25, 2026.

As of June 29, 2024, and in accordance with 49 U.S.C. 31136(e) and

31315(b), the following two individuals have satisfied the renewal conditions for obtaining an exemption from the hearing requirement in the FMCSRs for interstate CMV drivers:

Leroy Carter (OH); and Richard Fisher (PA).

The drivers were included in docket number FMCSA–2017–0060. Their exemptions are applicable as of June 29, 2024 and will expire on June 29, 2026.

V. Conditions and Requirements

The exemptions are extended subject to the following conditions: (1) each driver must report any crashes or accidents as defined in § 390.5T; and (2) report all citations and convictions for disqualifying offenses under 49 CFR parts 383 and 391 to FMCSA; and (3) each driver prohibited from operating a motorcoach or bus with passengers in interstate commerce. The driver must also have a copy of the exemption when driving, for presentation to a duly authorized Federal, State, or local enforcement official. In addition, the exemption does not exempt the individual from meeting the applicable CDL testing requirements. Each exemption will be valid for 2 years unless rescinded earlier by FMCSA. The exemption will be rescinded if: (1) the person fails to comply with the terms and conditions of the exemption; (2) the exemption has resulted in a lower level of safety than was maintained before it was granted; or (3) continuation of the exemption would not be consistent with the goals and objectives of 49 U.S.C. 31136(e) and 31315(b).

VI. Preemption

During the period the exemption is in effect, no State shall enforce any law or regulation that conflicts with this exemption with respect to a person operating under the exemption.

VII. Conclusion

Based upon its evaluation of the 34 exemption applications, FMCSA renews the exemptions of the aforementioned drivers from the hearing requirement in § 391.41 (b)(11). In accordance with 49 U.S.C. 31136(e) and 31315(b), each exemption will be valid for 2 years unless revoked earlier by FMCSA.

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2024–12723 Filed 6–10–24; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA–2013–0108; FMCSA–2013–0443; FMCSA–2014–0381; FMCSA–2015–0115; FMCSA–2015–0320; FMCSA–2015–0321; FMCSA–2017–0254; FMCSA–2018–0050; FMCSA–2019–0034; FMCSA–2020–0045; FMCSA–2022–0042; FMCSA–2022–0043]

Qualification of Drivers; Exemption Applications; Epilepsy and Seizure Disorders

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of renewal of exemptions; request for comments.

SUMMARY: FMCSA announces its decision to renew exemptions for 18 individuals from the requirement in the Federal Motor Carrier Safety Regulations (FMCSRs) that interstate commercial motor vehicle (CMV) drivers have “no established medical history or clinical diagnosis of epilepsy or any other condition which is likely to cause loss of consciousness or any loss of ability to control a CMV.” The exemptions enable these individuals who have had one or more seizures and are taking anti-seizure medication to continue to operate CMVs in interstate commerce.

DATES: The exemptions are applicable on June 28, 2024. The exemptions expire on June 28, 2026. Comments must be received on or before July 11, 2024.

ADDRESSES: You may submit comments identified by the Federal Docket Management System Docket No. FMCSA–2013–0108, Docket No. FMCSA–2013–0443, Docket No. FMCSA–2014–0381, Docket No. FMCSA–2015–0115, Docket No. FMCSA–2015–0320, Docket No. FMCSA–2015–0321, Docket No. FMCSA–2017–0254, Docket No. FMCSA–2018–0050, Docket No. FMCSA–2019–0034, Docket No. FMCSA–2020–0045, Docket No. FMCSA–2022–0042, or Docket No. FMCSA–2022–0043 using any of the following methods:

- *Federal eRulemaking Portal:* Go to www.regulations.gov/; insert the docket number (FMCSA–2013–0108, FMCSA–2013–0443, FMCSA–2014–0381, FMCSA–2015–0115, FMCSA–2015–0320, FMCSA–2015–0321, FMCSA–2017–0254, FMCSA–2018–0050, FMCSA–2019–0034, FMCSA–2020–0045, FMCSA–2022–0042, or FMCSA–2022–0043) in the keyword box and

click “Search.” Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, and click on the “Comment” button. Follow the online instructions for submitting comments.

- *Mail:* Dockets Operations; U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building Ground Floor, Washington, DC 20590–0001.

- *Hand Delivery:* West Building Ground Floor, 1200 New Jersey Avenue SE, Washington, DC, 20590–0001 between 9 a.m. and 5 p.m. ET Monday through Friday, except Federal Holidays.

- *Fax:* (202) 493–2251.

To avoid duplication, please use only one of these four methods. See the “Public Participation” portion of the **SUPPLEMENTARY INFORMATION** section for instructions on submitting comments.

FOR FURTHER INFORMATION CONTACT: Ms. Christine A. Hydock, Chief, Medical Programs Division, FMCSA, DOT, 1200 New Jersey Avenue SE, Washington, DC 20590–0001, (202) 366–4001, fmcamedical@dot.gov. Office hours are from 8:30 a.m. to 5 p.m. ET Monday through Friday, except Federal holidays. If you have questions regarding viewing or submitting material to the docket, contact Dockets Operations, (202) 366–9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation

A. Submitting Comments

If you submit a comment, please include the docket number for this notice (Docket No. FMCSA–2013–0108, Docket No. FMCSA–2013–0443, Docket No. FMCSA–2014–0381, Docket No. FMCSA–2015–0115, Docket No. FMCSA–2015–0320, Docket No. FMCSA–2015–0321, Docket No. FMCSA–2017–0254, Docket No. FMCSA–2018–0050, Docket No. FMCSA–2019–0034, Docket No. FMCSA–2020–0045, Docket No. FMCSA–2022–0042, or Docket No. FMCSA–2022–0043), indicate the specific section of this document to which each comment applies, and provide a reason for each suggestion or recommendation. You may submit your comments and material online or by fax, mail, or hand delivery, but please use only one of these means. FMCSA recommends that you include your name and a mailing address, an email address, or a phone number in the body of your document so that FMCSA can contact you if there are questions regarding your submission.

To submit your comment online, go to www.regulations.gov/, insert the docket number (FMCSA–2013–0108, FMCSA–

2013–0443, FMCSA–2014–0381, FMCSA–2015–0115, FMCSA–2015–0320, FMCSA–2015–0321, FMCSA–2017–0254, FMCSA–2018–0050, FMCSA–2019–0034, FMCSA–2020–0045, FMCSA–2022–0042, or FMCSA–2022–0043) in the keyword box and click “Search.” Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, click the “Comment” button, and type your comment into the text box on the following screen. Choose whether you are submitting your comment as an individual or on behalf of a third party and then submit.

If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. FMCSA will consider all comments and material received during the comment period.

B. Viewing Comments

To view comments go to www.regulations.gov. Insert the docket number (FMCSA–2013–0108, FMCSA–2013–0443, FMCSA–2014–0381, FMCSA–2015–0115, FMCSA–2015–0320, FMCSA–2015–0321, FMCSA–2017–0254, FMCSA–2018–0050, FMCSA–2019–0034, FMCSA–2020–0045, FMCSA–2022–0042, or FMCSA–2022–0043) in the keyword box and click “Search.” Next, sort the results by “Posted (Newer-Older),” choose the first notice listed, and click “Browse Comments.” 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 20590–0001, 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.

C. Privacy Act

In accordance with 49 U.S.C. 31315(b)(6), DOT solicits comments from the public on the exemption request. 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 (Federal Docket Management System), which can be reviewed at <https://www.transportation.gov/individuals/privacy/privacy-act-system-records-notices>, the comments are searchable by the name of the submitter.

II. Background

Under 49 U.S.C. 31136(e) and 31315(b), FMCSA may grant an exemption from the FMCSRs for no

longer than a 5-year period if it finds such exemption would likely achieve a level of safety that is equivalent to, or greater than, the level that would be achieved absent such exemption. The statutes also allow the Agency to renew exemptions at the end of the 5-year period. However, FMCSA grants medical exemptions from the FMCSRs for a 2-year period to align with the maximum duration of a driver’s medical certification.

The physical qualification standard for drivers regarding epilepsy found in 49 CFR 391.41(b)(8) states that a person is physically qualified to drive a CMV if that person has no established medical history or clinical diagnosis of epilepsy or any other condition which is likely to cause the loss of consciousness or any loss of ability to control a CMV.

In addition to the regulations, FMCSA has published advisory criteria¹ to assist Medical Examiners in determining whether drivers with certain medical conditions are qualified to operate a CMV in interstate commerce.

The 18 individuals listed in this notice have requested renewal of their exemptions from the epilepsy and seizure disorders prohibition in § 391.41(b)(8), in accordance with FMCSA procedures. Accordingly, FMCSA has evaluated these applications for renewal on their merits and decided to extend each exemption for a renewable 2-year period.

III. Request for Comments

Interested parties or organizations possessing information that would otherwise show that any, or all, of these drivers are not currently achieving the statutory level of safety should immediately notify FMCSA. The Agency will evaluate any adverse evidence submitted and, if safety is being compromised or if continuation of the exemption would not be consistent with the goals and objectives of 49 U.S.C. 31136(e) and 31315(b), FMCSA will take immediate steps to revoke the exemption of a driver.

IV. Basis for Renewing Exemptions

In accordance with 49 U.S.C. 31136(e) and 31315(b), each of the 18 applicants has satisfied the renewal conditions for obtaining an exemption from the epilepsy and seizure disorders prohibition. The 18 drivers in this

notice remain in good standing with the Agency, have maintained their medical monitoring and have not exhibited any medical issues that would compromise their ability to safely operate a CMV during the previous 2-year exemption period. In addition, for commercial driver’s license (CDL) holders, the Commercial Driver’s License Information System and the Motor Carrier Management Information System are searched for crash and violation data. For non-CDL holders, the Agency reviews the driving records from the State Driver’s Licensing Agency. These factors provide an adequate basis for predicting each driver’s ability to continue to safely operate a CMV in interstate commerce. Therefore, FMCSA concludes that extending the exemption for each renewal applicant for a period of 2 years is likely to achieve a level of safety equal to that existing without the exemption.

As of June 28, 2024, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following 18 individuals have satisfied the renewal conditions for obtaining an exemption from the epilepsy and seizure disorders prohibition in the FMCSRs for interstate CMV drivers:

Randall Bernath (MI)
James Crow (ME)
Paul Drewer (WA)
Jeremy Fehrman (WI)
David Funk (OH)
Scott Gessner (PA)
Daniel Halstead (NV)
Aaron Harms (MO)
John Holland, II (IN)
Scott Hughes (IL)
Brian Johnson (MN)
Larry Lintelman (AK)
Michael Miller (WI)
Chad Smith (MA)
Daniel Verduzco (CA)
Mohammad Warrad (IA)
Michael Weymouth (NH)
Karl Wilson, Jr. (GA)

The drivers were included in docket number FMCSA–2013–0108, FMCSA–2013–0443, FMCSA–2014–0381, FMCSA–2015–0115, FMCSA–2015–0320, FMCSA–2015–0321, FMCSA–2017–0254, FMCSA–2018–0050, FMCSA–2019–0034, FMCSA–2020–0045, FMCSA–2022–0042, or FMCSA–2022–0043. Their exemptions are applicable as of June 28, 2024 and will expire on June 28, 2026.

V. Conditions and Requirements

The exemptions are extended subject to the following conditions: (1) each driver must remain seizure-free and maintain a stable treatment during the 2-year exemption period; (2) each driver

¹ These criteria may be found in APPENDIX A TO PART 391—MEDICAL ADVISORY CRITERIA, section H. *Epilepsy*: § 391.41(b)(8), paragraphs 3, 4, and 5, which is available on the internet at <https://www.gpo.gov/fdsys/pkg/CFR-2015-title49-vol5/pdf/CFR-2015-title49-vol5-part391-appA.pdf>.

must submit annual reports from their treating physicians attesting to the stability of treatment and that the driver has remained seizure-free; (3) each driver must undergo an annual medical examination by a certified ME, as defined by § 390.5; and (4) each driver must provide a copy of the annual medical certification to the employer for retention in the driver's qualification file, or keep a copy of his/her driver's qualification file if he/she is self-employed. The driver must also have a copy of the exemption when driving, for presentation to a duly authorized Federal, State, or local enforcement official. The exemption will be rescinded if: (1) the person fails to comply with the terms and conditions of the exemption; (2) the exemption has resulted in a lower level of safety than was maintained before it was granted; or (3) continuation of the exemption would not be consistent with the goals and objectives of 49 U.S.C. 31136(e) and 31315(b).

VI. Preemption

During the period the exemption is in effect, no State shall enforce any law or regulation that conflicts with this exemption with respect to a person operating under the exemption.

VII. Conclusion

Based on its evaluation of the 18 exemption applications, FMCSA renews the exemptions of the aforementioned drivers from the epilepsy and seizure disorders prohibition in § 391.41(b)(8). In accordance with 49 U.S.C. 31136(e) and 31315(b), each exemption will be valid for 2 years unless revoked earlier by FMCSA.

Larry W. Minor,
Associate Administrator for Policy.

[FR Doc. 2024-12726 Filed 6-10-24; 8:45 am]

BILLING CODE 4910-EX-P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA-2024-0125]

Commercial Driver's License; 3 North LLC; Application for Exemption

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of application for exemption; request for comments.

SUMMARY: FMCSA announces that it has received an application from 3 North LLC for a 5-year exemption to enable 3 of its commercial driver's license (CDL)

holders under the age of 21, with the requisite "K" restriction for intrastate-only operations, to drive commercial motor vehicles (CMVs) in intrastate operations in a State other than their State of domicile. The applicant indicates these individuals will drive less than 20 miles per day in intrastate commerce. FMCSA requests public comment on the applicant's request for exemption.

DATES: Comments must be received on or before July 11, 2024.

ADDRESSES: You may submit comments identified by Federal Docket Management System (FDMS) Number FMCSA-2024-0125 by any of the following methods:

- **Federal eRulemaking Portal:** www.regulations.gov. See the Public Participation and Request for Comments section below for further information.
- **Mail:** Dockets Operations, U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building, Ground Floor, Washington, DC 20590-0001.
- **Hand Delivery or Courier:** West Building, Ground Floor, 1200 New Jersey Avenue SE, between 9 a.m. and 5 p.m. E.T., Monday through Friday, except Federal holidays.
- **Fax:** (202) 493-2251.

Each submission must include the Agency name and the docket number (FMCSA-2024-0125) for this notice. Note that DOT posts all comments received without change to www.regulations.gov, including any personal information included in a comment. Please see the Privacy Act heading below.

Docket: If you do not have access to the internet, you may view the docket by visiting Docket 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.

Privacy Act: In accordance with 49 U.S.C. 31315(b), DOT solicits comments from the public to better inform its exemption process. DOT posts these comments, 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>. The comments are posted without edit and are searchable by the name of the submitter.

FOR FURTHER INFORMATION CONTACT: Ms. Bernadette Walker, Driver, and Carrier

Operations Division; Office of Carrier, Driver and Vehicle Safety Standards, FMCSA; (202) 385-2415; bernadette.walker@dot.gov. If you have questions on viewing or submitting material to the docket, contact Dockets Operations at (202) 366-9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation and Request for Comments

FMCSA encourages you to participate by submitting comments and related materials.

Submitting Comments

If you submit a comment, please include the docket number for this notice (FMCSA-2024-0125), indicate the specific section of this document to which the comment applies, and provide a reason for your suggestions or recommendations. You may submit your comments and material online or by fax, mail, or hand delivery, but please use only one of these means. FMCSA recommends that you include your name and a mailing address, an email address, or a phone number in the body of your document so the Agency can contact you if it has questions regarding your submission.

To submit your comment online, go to www.regulations.gov, enter the docket number "FMCSA-2024-0125" in the keyword box, and click "Search." Next, sort the results by "Posted (Newer-Older)," choose the first notice listed, click the "Comment" button, and type your comment into the text box on the following screen. Choose whether you are submitting your comment as an individual or on behalf of a third party and then submit. If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. If you submit comments by mail and would like to know that they reached the facility, please enclose a stamped, self-addressed postcard or envelope. FMCSA will consider all comments and material received during the comment period.

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 the applicant's safety analyses. 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 maintain 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(s) 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. Applicant's Request

The applicant, 3 North LLC, requests a 5-year exemption for 3 drivers from 49 CFR 383.153(a)(10)(vii), which requires that CDLs issued to drivers under the age of 21 be marked with a "K" restriction limiting them to intrastate operations in the driver's State of domicile. The applicant utilizes a fleet of specialized construction equipment mounted on a straight truck chassis to transport concrete for wind turbine foundations. The applicant stated that it uses a different set of CDL holders to drive the CMVs across State lines. The exemption request is applicable to three drivers who would operate the CMVs in the State where work is being performed, but only after they have been driven to the State by CDL holders over the age of 21. The applicant believes their operations would have no impact on the safety of U.S. highways because the three drivers will operate the CMVs for only 20 miles in one State once the CMVs have been driven from one State to another. The applicant believes that, absent the exemption, the progress towards green, renewable energy could be delayed, potentially causing the energy sector to postpone its transition away from carbon-generating sources of power.

A copy of 3 North LLC's application for exemption is available for review in the docket for this notice.

IV. Request for Comments

In accordance with 49 U.S.C. 31315(b), FMCSA requests public comment from all interested persons on 3 North LLC's exemption application. All comments received before the close of business on the comment closing date indicated at the beginning of this notice will be considered and will be available for examination in the docket at the location listed under the Addresses section of this notice. Comments

received after the comment closing date will be filed in the public docket and will be considered to the extent practicable. In addition to late comments, FMCSA will also continue to file, in the public docket, relevant information that becomes available after the comment closing date. Interested persons should continue to examine the public docket for new material.

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2024-12767 Filed 6-10-24; 8:45 am]

BILLING CODE 4910-EX-P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA-2024-0011]

Qualification of Drivers; Exemption Applications; Hearing

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of applications for exemption; request for comments.

SUMMARY: FMCSA announces receipt of applications from 11 individuals for an exemption from the hearing requirement in the Federal Motor Carrier Safety Regulations (FMCSRs) to operate a commercial motor vehicle (CMV) in interstate commerce. If granted, the exemptions would enable these hard of hearing and deaf individuals to operate CMVs in interstate commerce.

DATES: Comments must be received on or before July 11, 2024.

ADDRESSES: You may submit comments identified by the Federal Docket Management System Docket No. FMCSA-2024-0011 using any of the following methods:

- **Federal eRulemaking Portal:** Go to www.regulations.gov/, insert the docket number (FMCSA-2024-0011) in the keyword box and click "Search." Next, choose the only notice listed, and click on the "Comment" button. Follow the online instructions for submitting comments.

- **Mail:** Dockets Operations; U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building Ground Floor, Washington, DC 20590-0001.

- **Hand Delivery:** West Building Ground Floor, 1200 New Jersey Avenue SE, Washington, DC 20590-0001, between 9 a.m. and 5 p.m. ET Monday through Friday, except Federal Holidays.

- **Fax:** (202) 493-2251.

To avoid duplication, please use only one of these four methods. See the "Public Participation" portion of the **SUPPLEMENTARY INFORMATION** section for instructions on submitting comments.

FOR FURTHER INFORMATION CONTACT: Ms. Christine A. Hydock, Chief, Medical Programs Division, FMCSA, DOT, 1200 New Jersey Avenue SE, Room W64-224, Washington, DC 20590-0001, (202) 366-4001, fmcsamedical@dot.gov. Office hours are 8:30 a.m. to 5 p.m. ET Monday through Friday, except Federal holidays. If you have questions regarding viewing or submitting material to the docket, contact Dockets Operations, (202) 366-9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation

A. Submitting Comments

If you submit a comment, please include the docket number for this notice (Docket No. FMCSA-2024-0011), indicate the specific section of this document to which each comment applies, and provide a reason for each suggestion or recommendation. You may submit your comments and material online or by fax, mail, or hand delivery, but please use only one of these means. FMCSA recommends that you include your name and a mailing address, an email address, or a phone number in the body of your document so that FMCSA can contact you if there are questions regarding your submission.

To submit your comment online, go to <https://www.regulations.gov/docket/FMCSA-2024-0011>. Next, sort the results by "Posted (Newer-Older)," choose the only notice listed, click the "Comment" button, and type your comment into the text box on the following screen. Choose whether you are submitting your comment as an individual or on behalf of a third party and then submit.

If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. FMCSA will consider all comments and material received during the comment period.

B. Viewing Comments

To view comments go to www.regulations.gov. Insert the docket number (FMCSA-2024-0011) in the keyword box and click "Search." Next, choose the only notice listed, and click "Browse Comments." 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 20590–0001, 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.

C. Privacy Act

In accordance with 49 U.S.C. 31315(b)(6), DOT solicits comments from the public on the exemption requests. 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 (Federal Docket Management System), which can be reviewed at <https://www.transportation.gov/individuals/privacy/privacy-act-system-records-notices>, the comments are searchable by the name of the submitter.

II. Background

Under 49 U.S.C. 31136(e) and 31315(b), FMCSA may grant an exemption from the FMCSRs for no longer than a 5-year period if it finds such exemption would likely achieve a level of safety that is equivalent to, or greater than, the level that would be achieved absent such exemption. The statutes also allow the Agency to renew exemptions at the end of the 5-year period. FMCSA grants medical exemptions from the FMCSRs for a 2-year period to align with the maximum duration of a driver's medical certification.

The 11 individuals listed in this notice have requested an exemption from the hearing requirement in 49 CFR 391.41(b)(11). Accordingly, the Agency will evaluate the qualifications of each applicant to determine whether granting the exemption will achieve the required level of safety mandated by statute.

The physical qualification standard for drivers regarding hearing found in § 391.41(b)(11) states that a person is physically qualified to drive a CMV if that person first perceives a forced whispered voice in the better ear at not less than 5 feet with or without the use of a hearing aid or, if tested by use of an audiometric device, does not have an average hearing loss in the better ear greater than 40 decibels at 500 Hz, 1,000 Hz, and 2,000 Hz with or without a hearing aid when the audiometric device is calibrated to American National Standard (formerly ASA Standard) Z24.5–1951.

This standard was adopted in 1970 and was revised in 1971 to allow drivers to be qualified under this standard while wearing a hearing aid, (35 FR

6458, 6463 (Apr. 22, 1970) and 36 FR 12857 (July 8, 1971), respectively).

On February 1, 2013, FMCSA announced in a Notice of Final Disposition titled, “Qualification of Drivers; Application for Exemptions; National Association of the Deaf,” (78 FR 7479), its decision to grant requests from 40 individuals for exemptions from the Agency's physical qualification standard concerning hearing for interstate CMV drivers. Since that time the Agency has published additional notices granting requests from hard of hearing and deaf individuals for exemptions from the Agency's physical qualification standard concerning hearing for interstate CMV drivers.

III. Qualifications of Applicants

Anderson Aberdeen

Anderson Aberdeen, 42, holds a class R driver's license in Colorado.

Ismael Aguirre

Ismael Aguirre, 32, holds a class C driver's license in California.

Ulices Coria

Ulices Coria, 45, holds a class D driver's license in Utah.

Manuel Llano Hevia

Manuel Llano Hevia, 42, holds a class C driver's license in Nevada.

Stan Lockett

Stan Lockett, 39, holds a class CM driver's license in Texas.

Joe Martens

Joe Martens, 66, holds a class D driver's license in Illinois.

Dejan Ortiz

Dejan Ortiz, 20, holds a class C driver's license in Texas.

Elyssa Simmons

Elyssa Simmons, 24, holds a class D driver's license in Virginia.

Tamel Smith

Tamel Smith, 27, holds a class DM driver's license in New York.

Anton Syntax

Anton Syntax, 76, holds a class C driver's license in Pennsylvania.

Jonathan Wilke

Jonathan Wilke, 21, holds a class A driver's license in Iowa.

IV. Request for Comments

In accordance with 49 U.S.C. 31136(e) and 31315(b), FMCSA requests public comment from all interested persons on the exemption petitions described in

this notice. We will consider all comments received before the close of business on the closing date indicated under the **DATES** section of the notice.

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2024–12725 Filed 6–10–24; 8:45 am]

BILLING CODE 4910–EX–P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA–2023–0266]

Commercial Driver's License: Oregon Department of Transportation; Application for Exemption

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of application for exemption; request for comments.

SUMMARY: FMCSA announces that the Oregon Department of Transportation (Oregon) has applied for a limited exemption from the commercial driver's license (CDL) rules concerning acceptable proof of citizenship or lawful permanent residency for citizens of Freely Associated States (FAS) who now reside in Oregon and wish to obtain a CDL. The FAS are the Federated States of Micronesia, the Republic of the Marshall Islands, and the Republic of Palau. If the exemption is granted, Oregon would be allowed to issue standard commercial learner permits (CLPs) and CDLs to these individuals, rather than issuing non-domiciled CLPs and CDLs. FMCSA requests public comment on the applicant's request for exemption.

DATES: Comments must be received on or before July 11, 2024.

ADDRESSES: You may submit comments identified by Federal Docket Management System (FDMS) Number FMCSA–2023–0266 by any of the following methods:

- *Federal eRulemaking Portal:* www.regulations.gov. See the Public Participation and Request for Comments section below for further information.
- *Mail:* Dockets Operations, U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building, Ground Floor, Washington, DC 20590–0001.
- *Hand Delivery or Courier:* West Building, Ground Floor, 1200 New Jersey Avenue SE, Washington, DC, between 9 a.m. and 5 p.m. E.T., Monday through Friday, except Federal holidays.
- *Fax:* (202) 493–2251.

Each submission must include the Agency name and the docket number (FMCSA–2023–0266) for this notice. Note that DOT posts all comments received without change to www.regulations.gov, including any personal information included in a comment. Please see the Privacy Act heading below.

Docket: If you do not have access to the internet, you may view the docket by visiting Docket 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.

Privacy Act: In accordance with 49 U.S.C. 31315(b), DOT solicits comments from the public to better inform its exemption process. DOT posts these comments, 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>. The comments are posted without edit and are searchable by the name of the submitter.

FOR FURTHER INFORMATION CONTACT: Ms. Pearlle Robinson, Driver and Carrier Operations Division; Office of Carrier, Driver and Vehicle Safety Standards, FMCSA; 1200 New Jersey Avenue SE, Washington, DC 20590–0001; (202) 366–4225; pearlie.robinson@dot.gov. If you have questions on viewing or submitting material to the docket, contact Dockets Operations at (202) 366–9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation and Request for Comments

FMCSA encourages you to participate by submitting comments and related materials.

Submitting Comments

If you submit a comment, please include the docket number for this notice (FMCSA–2023–0266), indicate the specific section of this document to which the comment applies, and provide a reason for your suggestions or recommendations. You may submit your comments and material online or by fax, mail, or hand delivery, but please use only one of these means. FMCSA recommends that you include your name and a mailing address, an email address, or a phone number in the body of your document so the Agency can contact you if it has questions regarding your submission.

To submit your comment online, go to www.regulations.gov and put the docket number “FMCSA–2023–0266” in the “Keyword” box, and click “Search.” When the new screen appears, click on the “Comment” button and type your comment into the text box in the following screen. Choose whether you are submitting your comment as an individual or on behalf of a third party and then submit. If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. If you submit comments by mail and would like to know that they reached the facility, please enclose a stamped, self-addressed postcard or envelope. FMCSA will consider all comments and material received during the comment period.

Confidential Business Information (CBI)

CBI is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (5 U.S.C. 552), CBI is exempt from public disclosure. If your comments responsive to the 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 the notice, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission that constitutes CBI as “PROPIN” to indicate it contains proprietary information. FMCSA will treat such marked submissions as confidential under the Freedom of Information Act, and they will not be placed in the public docket of the notice. Submissions containing CBI should be sent to Brian Dahlin, Chief, Regulatory Evaluation Division, Office of Policy, FMCSA, 1200 New Jersey Avenue SE, Washington, DC 20590–0001 or via email at brian.g.dahlin@dot.gov. At this time, you need not send a duplicate hardcopy of your electronic CBI submissions to FMCSA headquarters. Any comments FMCSA receives not specifically designated as CBI will be placed in the public docket for this notice.

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 the applicant’s safety analyses.

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(s) 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 reasons for the denial (49 CFR 381.315(c)(2)).

III. Background

Under 49 CFR 383.71(b), a State Driver Licensing Agency (SDLA) may issue a CDL or CLP only to an applicant who presents proof of United States citizenship or lawful permanent residency. If the applicant cannot present this proof, then the SDLA may issue the applicant a non-domiciled CDL or CPL instead, under 49 CFR 383.71(f). Thus, under 49 CFR 383.71, an individual who is a citizen of a FAS, who does not have status of lawful permanent residence, is not eligible for a CDL or CLP and may be issued only non-domiciled credentials.

The United States’ relationships with the FAS are governed by agreements known as Compacts of Free Association (COFA). Under these agreements, citizens of the FAS may enter the United States as nonimmigrants, and, without obtaining a visa, they may remain in and work in the country indefinitely.¹

Under the REAL ID Act of 2005² and its accompanying regulation 6 CFR part 37 promulgated by the Department of Homeland Security (DHS),³ REAL ID compliant States are permitted to issue REAL ID compliant driver’s licenses and identification cards to certain individuals with nonimmigrant status. However, under 6 CFR 37.21(b)(1), if the individual has no end date to their authorized stay in the country, then the license or ID may be issued and valid for a maximum of one year. Because citizens of the FAS may remain in the country indefinitely, initially under this law, these individuals could be issued

¹ See H. Rept. 115–945.

² Public Law 109–13, Div. B.

³ See 73 FR 5272 (January 29, 2008).

REAL ID driver's licenses and ID cards lasting only one year.⁴

Subsequently, Congress enacted a modifying statute entitled the REAL ID Act Modification for Freely Associated States Act,⁵ and DHS issued a corresponding amendment to its regulation. These changes permitted compliant States to issue full-term REAL ID licenses and ID cards to citizens of the FAS. When issuing this regulatory amendment, DHS also modified the identification documents that citizens of the FAS may present when applying for a REAL ID driver's license or ID card from a compliant State.⁶ Under its authority in 6 CFR 37.11(c)(1)(x), DHS stated that complying States may accept "a valid unexpired passport issued by the Republic of the Marshall Islands, the Republic of Palau, or the Federated States of Micronesia with an approved Form I-94 . . . documenting the applicant's most recent admission to the United States under the Compact of Free Association between the United States and the nation that issued the passport." DHS further stated its allowance of these documents was "consistent with the intent of Congress."⁷

Applicant's Request

Oregon seeks an exemption from the CDL "List of Acceptable Proofs of Citizenship or Lawful Permanent Residency" requirements in table 1 to 49 CFR 383.71 for citizens of the FAS. Oregon cited in its application the REAL ID Act Modification for Freely Associated States Act and the amended DHS regulations ensuring that citizens of the FAS residing in the United States are eligible for full-term REAL ID licenses and identification cards. According to Oregon, "citizens of the Freely Associated States are able to meet the domicile requirement described in [49 CFR] 383.71(b)(10)" and noted that "the [COFAs] provide for citizens of the Freely Associated States to reside and work indefinitely within the United States."

Oregon requests that FMCSA grant the proposed exemption and authorize it to issue CDLs and CLPs to citizens of the FAS in accordance with State procedures in 49 CFR 383.73(a) and (b). Ordinarily, a person who is not a United States citizen must present a valid, unexpired Permanent Resident Card. For a person who is a citizen of a FAS, Oregon would instead accept a valid, unexpired passport issued by a FAS and

an Arrival/Departure Record, meaning an I-94 or I-94A form, to prove that the individual has entered the United States lawfully. A copy of the Oregon's application for exemption is available for review in the docket for this notice.

IV. Request for Comments

In accordance with 49 U.S.C. 31315(b), FMCSA requests public comment from all interested persons on Oregon's application for an exemption from the requirement in table 1 to 49 CFR 383.71 for citizens of the FAS. All comments received before the close of business on the comment closing date indicated at the beginning of this notice will be considered and will be available for examination in the docket at the location listed under the **ADDRESSES** section of this notice. Comments received after the comment closing date will be filed in the public docket and will be considered to the extent practicable. In addition to late comments, FMCSA will also continue to file, in the public docket, relevant information that becomes available after the comment closing date. Interested persons should continue to examine the public docket for new material.

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2024-12766 Filed 6-10-24; 8:45 am]

BILLING CODE 4910-EX-P

DEPARTMENT OF TRANSPORTATION

Federal Motor Carrier Safety Administration

[Docket No. FMCSA-2013-0106; FMCSA-2013-0442; FMCSA-2015-0115; FMCSA-2015-0119; FMCSA-2015-0321; FMCSA-2017-0181; FMCSA-2017-0254; FMCSA-2019-0030; FMCSA-2019-0036; FMCSA-2019-0206; FMCSA-2020-0045; FMCSA-2020-0046; FMCSA-2021-0026; FMCSA-2022-0042]

Qualification of Drivers; Exemption Applications; Epilepsy and Seizure Disorders

AGENCY: Federal Motor Carrier Safety Administration (FMCSA), Department of Transportation (DOT).

ACTION: Notice of final disposition.

SUMMARY: FMCSA announces its decision to renew exemptions for 22 individuals from the requirement in the Federal Motor Carrier Safety Regulations (FMCSRs) that interstate commercial motor vehicle (CMV) drivers have "no established medical history or clinical diagnosis of epilepsy or any other condition which is likely to cause loss of consciousness or any

loss of ability to control a CMV." The exemptions enable these individuals who have had one or more seizures and are taking anti-seizure medication to continue to operate CMVs in interstate commerce.

DATES: Each group of renewed exemptions were applicable on the dates stated in the discussions below and will expire on the dates provided below.

FOR FURTHER INFORMATION CONTACT: Ms. Christine A. Hydock, Chief, Medical Programs Division, FMCSA, DOT, 1200 New Jersey Avenue SE, Washington, DC 20590-0001, (202) 366-4001, fmcamedical@dot.gov. Office hours are from 8:30 a.m. to 5 p.m. ET Monday through Friday, except Federal holidays. If you have questions regarding viewing or submitting material to the docket, contact Dockets Operations, (202) 366-9826.

SUPPLEMENTARY INFORMATION:

I. Public Participation

A. Viewing Comments

To view comments go to www.regulations.gov. Insert the docket number (FMCSA-2013-0106, FMCSA-2013-0442, FMCSA-2015-0115, FMCSA-2015-0119, FMCSA-2015-0321, FMCSA-2017-0181, FMCSA-2017-0254, FMCSA-2019-0030, FMCSA-2019-0036, FMCSA-2019-0206, FMCSA-2020-0045, FMCSA-2020-0046, FMCSA-2021-0026, or FMCSA-2022-0042) in the keyword box and click "Search." Next, sort the results by "Posted (Newer-Older)," choose the first notice listed, and click "Browse Comments." 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 20590-0001, 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.

B. Privacy Act

In accordance with 49 U.S.C. 31315(b)(6), DOT solicits comments from the public on the exemption request. 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 (Federal Docket Management System), which can be reviewed at <https://www.transportation.gov/individuals/privacy/privacy-act-system->

⁴ See 84 FR 46423 (September 4, 2019).

⁵ Public Law 115-323.

⁶ See 84 FR 46556 (September 4, 2019).

⁷ Id.

records-notices, the comments are searchable by the name of the submitter.

II. Background

On April 25, 2024, FMCSA published a notice announcing its decision to renew exemptions for 22 individuals from the epilepsy and seizure disorders prohibition in 49 CFR 391.41(b)(8) to operate a CMV in interstate commerce and requested comments from the public (89 FR 31794). The public comment period ended on May 28, 2024, and no comments were received.

FMCSA has evaluated the eligibility of these applicants and determined that renewing these exemptions would likely achieve a level of safety that is equivalent to, or greater than, the level that would be achieved by complying with § 391.41(b)(8).

The physical qualification standard for drivers regarding epilepsy found in § 391.41(b)(8) states that a person is physically qualified to drive a CMV if that person has no established medical history or clinical diagnosis of epilepsy or any other condition which is likely to cause the loss of consciousness or any loss of ability to control a CMV.

In addition to the regulations, FMCSA has published advisory criteria¹ to assist medical examiners in determining whether drivers with certain medical conditions are qualified to operate a CMV in interstate commerce.

III. Discussion of Comments

FMCSA received no comments in this proceeding.

IV. Conclusion

Based on its evaluation of the 22 renewal exemption applications and comments received, FMCSA announces its decision to exempt the following drivers from the epilepsy and seizure disorders prohibition in § 391.41(b)(8).

As of May 6, 2024, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following nine individuals have satisfied the renewal conditions for obtaining an exemption from the epilepsy and seizure disorders prohibition in the FMCSRs for interstate CMV drivers (89 FR 31794):

Gary Clark (KY)
Michael Curtis (DE)
Callon Hegman (IL)
Zachary Henson (IL)
Gregory Johnson (NC)
Robert Lombardo (CA)
Armando Macias-Tovar (FL)

Joseph Mendoza (IN)
Douglas Slagel (OH)

The drivers were included in docket number FMCSA–2013–0106, FMCSA–2017–0181, FMCSA–2021–0026, or FMCSA–2022–0042. Their exemptions were applicable as of May 6, 2024 and will expire on May 6, 2026.

As of May 15, 2024, and in accordance with 49 U.S.C. 31136(e) and 31315(b), the following 13 individuals have satisfied the renewal conditions for obtaining an exemption from the epilepsy and seizure disorders prohibition in the FMCSRs for interstate CMV drivers (89 FR 31794):

Barry Dull (OH)
Robert J. Forney (WI)
Matthew Heinen (MN)
Logan Hertzler (PA)
Preston Kanagy (TN)
Kenneth Lewis (NC)
Kevin Market (OH)
Gary Olsen (MN)
Randy Pinto (PA)
Jeffrey Totten (KS)
Paul Vitous (WA)
Thomas Vivirito (PA)
Robert J. Wenner (MN)

The drivers were included in docket number FMCSA–2013–0442, FMCSA–2015–0115, FMCSA–2015–0119, FMCSA–2015–0321, FMCSA–2017–0181, FMCSA–2017–0254, FMCSA–2019–0030, FMCSA–2019–0036, FMCSA–2020–0045, or FMCSA–2020–0046. Their exemptions were applicable as of May 15, 2024 and will expire on May 15, 2026.

In accordance with 49 U.S.C. 31315(b), each exemption will be valid for 2 years from the effective date unless revoked earlier by FMCSA. The exemption will be revoked if the following occurs: (1) the person fails to comply with the terms and conditions of the exemption; (2) the exemption has resulted in a lower level of safety than was maintained prior to being granted; or (3) continuation of the exemption would not be consistent with the goals and objectives of 49 U.S.C. 31136(e) and 31315(b).

Larry W. Minor,

Associate Administrator for Policy.

[FR Doc. 2024–12724 Filed 6–10–24; 8:45 am]

BILLING CODE 4910-EX-P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

[Docket No. NHTSA–2023–0063]

Agency Information Collection Activities; Submission to the Office of Management and Budget for Review and Approval; Request for Comment; Human Interaction With Driving Automation Systems

AGENCY: National Highway Traffic Safety Administration (NHTSA), Department of Transportation (DOT).

ACTION: Notice and request for comments on a request for approval of a new collection of information.

SUMMARY: In compliance with the Paperwork Reduction Act of 1995 (PRA), this notice announces that the Information Collection Request (ICR) summarized below will be submitted to the Office of Management and Budget (OMB) for review and approval. The ICR describes the nature of the information collection and its expected burden. The National Highway Traffic Safety Administration (NHTSA) invites public comments about our intention to request approval from the Office of Management and Budget (OMB) for a new information collection. The proposed collection of information described below supports research addressing safety-related aspects of drivers' interactions with driving automation systems. A **Federal Register** Notice with a 60-day comment period soliciting comments on the following information collection was published on December 12, 2023. Comments were received from the Insurance Institute for Highway Safety (IIHS).

DATES: Comments must be submitted on or before July 11, 2024.

ADDRESSES: Written comments and recommendations for the proposed information collection, including suggestions for reducing burden, should be submitted to the Office of Management and Budget at www.reginfo.gov/public/do/PRAMain. To find this particular information collection, select “Currently under Review—Open for Public Comment” or use the search function.

FOR FURTHER INFORMATION CONTACT: For additional information or access to background documents, contact: Eric Traube, Office of Vehicle Safety Research, Human Factors/Engineering Integration Division NSR–310, West Building, W46–424, 1200 New Jersey Ave SE, Washington, DC 20590; eric.traube@dot.gov. Please identify the

¹ These criteria may be found in APPENDIX A TO PART 391—MEDICAL ADVISORY CRITERIA, section H. *Epilepsy*: § 391.41(b)(8), paragraphs 3, 4, and 5, which is available on the internet at <https://www.gpo.gov/fdsys/pkg/CFR-2015-title49-vol5/pdf/CFR-2015-title49-vol5-part391-appA.pdf>.

relevant collection of information by referring to its OMB Control Number.

SUPPLEMENTARY INFORMATION: Under the PRA (44 U.S.C. 3501 *et seq.*), a Federal agency must receive approval from the Office of Management and Budget (OMB) before it collects certain information from the public and 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. In compliance with these requirements, this notice announces that the following information collection request will be submitted to OMB.

Title: Human Interaction with Driving Automation Systems

OMB Control Number: New.

Form Numbers: There are multiple forms for this collection including: Eligibility Questionnaire, NHTSA Form 1742; Informed Consent Study 1, NHTSA Form 1743; Informed Consent Study 2, NHTSA Form 1744; Informed Consent Study 3, NHTSA Form 1745; Pre-Drive Questionnaire, NHTSA Form 1746; Wellness Questionnaire, NHTSA Form 1747; In-Drive Questionnaire, NHTSA Form 1748; Post-Drive Questionnaire, NHTSA Form 1749.

Type of Request: New information collection.

Type of Review Requested: Regular.

Requested Expiration Date of

Approval: Three years from date of approval.

Summary of the Collection of Information:

The National Highway Traffic Safety Administration (NHTSA) has proposed to perform research involving the collection of information from the public as part of a multi-year effort to learn about how humans interact with driving automation systems (DAS). This research will support NHTSA in understanding the potential safety challenges associated with human-DAS interactions, particularly in the context of mixed traffic interactions where some vehicles have DAS and others do not. Within mixed traffic environments, vehicles may also have DAS that perform more or less of the driving task (*i.e.*, different levels of automation) and come with their own sets of expectations and limitations.

The research will involve human subjects testing using a driving simulator. The goal is to understand how drivers interact with driving automation systems, specifically in situations where the automation behaves unlike a human driver. The project will measure interactions between humans and driving automation systems by (1) examining

driving performance measures (such as takeover time and reaction time), (2) measuring understanding of the automation through questionnaires, (3) measuring trust in automation using questionnaires, and (4) measuring risk taking through questionnaires and a simple behavioral task on a computer. This research will add to NHTSA's state of knowledge and is not immediately intended to inform regulations or policy. The research will be conducted in three parts, referred to as Study 1, Study 2, and Study 3. All study procedures will be approved by the University of Iowa Institutional Review Board (IRB). Data collection will begin upon receipt of PRA clearance and will involve human-subjects data collection using the driving simulators at the University of Iowa Driving Safety Research Institute (DSRI).

The data collections will be performed once to obtain the target number of valid test participants. Study participants will be members of the general public and participation will be voluntary with monetary compensation provided. Participants will include licensed drivers aged 18 to 65 who are healthy and able to drive without assistive devices. Participants will be recruited using the DSRI registry and through email blasts to University of Iowa community.

The objective of the first study is to understand how humans interact with DAS in mixed traffic environments, driving environments where some vehicles have automated capabilities, and some vehicles are driven manually. In the first study, participants will participate in pairs with each participant driving a separate driving simulator but interacting in the same driving environment. Participants will experience one of two driving automation systems. Both members of the participant pair will provide informed consent, a pre-drive questionnaire, a training presentation, a familiarization drive, wellness questionnaires to screen for simulator sickness, a study drive, in-drive ratings of trust, a post-drive questionnaire, and a risk-propensity assessment. During the simulator drives, one member of the pair will perform a continuous drive along a specified route. The other member of the pair will complete three short drives where they interact with the other participant at specific points throughout the drive. The simulator will collect vehicle data (*e.g.*, brake inputs, steering wheel angle) and data about the surrounding environment (*e.g.*, distance to surrounding vehicles and lane markings). After the drives, participants will complete a questionnaire to assess

their understanding of the DAS and their trust in and acceptance of the DAS. Data will be analyzed to understand how human drivers interact with DAS in mixed traffic situations and to understand how humans understand and perceive automation in different situations.

Study 2 will focus on understanding the impact of different levels of automated system capability, defined by how well the automation can perform different driving behaviors. In the second study, participants will complete a drive in a driving simulator with a driving automation system. The study drive will contain situations to which the DAS must respond. Participants will be randomly assigned to one of three systems with different capabilities, defined by how well the automation can navigate the set of test situations. The simulator will collect vehicle data (*e.g.*, brake inputs, steering wheel angle) and data about the surrounding environment (*e.g.*, distance to surrounding vehicles and lane markings). After the drives, participants will complete a questionnaire to assess their understanding of the DAS and their trust in and acceptance of the DAS as well as a risk-propensity assessment. Data will be analyzed to understand how human drivers interact with DAS in mixed traffic situations and to understand how humans understand and perceive automation in different situations.

Study 3 will be similar to Study 2 but will focus on how the decision-making behaviors of the automated driving systems impact user experience and driving performance. In the third study, participants will complete a drive in a driving simulator with a driving automation system. The study drive will contain situations to which the DAS must respond. Participants will be randomly assigned to one of three systems with different capabilities, defined by how well the automation can navigate the set of test situations. Procedures for the three studies are identical apart from the study drive experienced.

These three studies will involve information collection through participant screening questions, a pre-drive questionnaire, a wellness questionnaire to measure simulator sickness symptoms, assessment of driving performance in a driving simulator with a situational trust questionnaire administered at points during the study drives, a post-drive questionnaire, and a behavioral assessment of risk-taking propensity called the balloon analogue risk task (BART).

The National Highway Traffic Safety Administration's (NHTSA) mission is to save lives, prevent injuries, and reduce economic costs associated with motor vehicle crashes. As new vehicle technologies are developed, it is prudent to ensure that they do not create any unintended decrease in safety. The safe deployment of driving automation systems, particularly when deployed in mixed traffic where some vehicles are controlled by automation and some are controlled manually, requires an understanding of how humans respond to and perceive different automation behavior. This work seeks to examine how drivers interact with driving automation systems in a wide sample of contexts and different levels of automation.

The collection of information will consist of

1. *Eligibility Questionnaire (NHTSA Form 1742)*.

2. *Informed Consent Study 1 (NHTSA Form 1743)*.

3. *Informed Consent Study 2 (NHTSA Form 1744)*.

4. *Informed Consent Study 3 (NHTSA Form 1745)*.

5. *Pre-Drive Questionnaire (NHTSA Form 1746)*.

6. *Wellness Questionnaire (NHTSA Form 1747)*.

7. Driving Behavior Assessment (Pre-Drive PowerPoint Training, Familiarization Drive, Study Drive with In-Drive Questionnaire (NHTSA Form 1748).

8. *Post-Drive Questionnaire (NHTSA Form 1749)*.

9. Balloon Analogue Risk Task (BART).

The information to be collected will be used for the following purposes:

1. *Eligibility Questionnaire (NHTSA Form 1742)*—Necessary for determining individuals' suitability for study participation based on driving experience and history, general health, and ability to safely drive in the simulator without health concerns. The Eligibility Questionnaire will solely be used to determine individuals' suitability for study participation and will not be analyzed in any way. These criteria will remain the same across studies.

2. *Informed Consent Study 1 (NHTSA Form 1743)*—Necessary for obtaining informed written consent from the participant to participate in the study. The form describes all study procedures, data storage and use, and potential risks from the study.

3. *Informed Consent Study 2 (NHTSA Form 1744)*—Necessary for obtaining informed written consent from the participant to participate in the study.

The form describes all study procedures, data storage and use, and potential risks from the study.

4. *Informed Consent Study 3 (NHTSA Form 1745)*—Necessary for obtaining informed written consent from the participant to participate in the study. The form describes all study procedures, data storage and use, and potential risks from the study.

5. *Pre-Drive Questionnaire (NHTSA Form 1746)*—Necessary for collecting data used to measure participants' understanding (*i.e.*, mental model) of DAS and their pre-drive trust in the DAS. Collecting these data before and after the drives will let us measure how exposure to the DAS impacts understanding and trust. Demographic information (*e.g.*, age, sex, gender, race, ethnicity) will also be collected. This pre-drive questionnaire will remain the same across all three studies.

6. *Wellness Questionnaire (NHTSA Form 1747)*—Necessary for evaluating simulator sickness symptoms to determine individuals' ability to complete the study drive in the driving simulator. This questionnaire will be administered pre-drive (to obtain baseline ratings), after the familiarization drive, and after the study drive. This wellness questionnaire will remain the same across all three studies.

7. Driving Behavior Assessment (Study Drive) with *In-Drive Questionnaire (NHTSA Form 1748)*—Before the study drive, participants will complete training via a PowerPoint presentation on a computer in a private study room. The presentation will introduce the simulator, the familiarization and study drive procedures, the DAS, and the non-driving email task. The familiarization drive is necessary to acclimate the participant to the driving simulator and perform a real-time determination for simulator sickness while training the participant on how to use the driving automation system. The study drive is necessary for gathering driving performance information for the purpose of assessing how drivers interact with automated systems and the impact of these interactions on safety. The in-drive questionnaire is necessary for understanding drivers' trust in the DAS at various points during the study drive. In Study 1, this information is collected after the events where the pair of research participants interact with one another. In Studies 2 & 3, this information is collected after the four events where the behavior of the automation varies across the different conditions. The information will be used to measure trust in the DAS following specific events. These

questions will remain the same across all three studies.

8. *Post-Drive Questionnaire (NHTSA Form 1749)*—Necessary for collecting data used to measure participants' understanding (*i.e.*, mental model) of DAS and their post-drive trust in the DAS, as well as general risk-taking behavior while driving. This post-drive questionnaire will remain the same across all three studies.

9. Balloon Analogue Risk Task (BART)—Necessary for measuring objective risk-taking propensity. For this computerized task, participants are presented with 20 different balloons (20 trials) and told that "the actual number of pumps for any particular balloon will vary." Participants are instructed to attempt to earn as many points as possible. At the beginning of each trial, the participant decides how many pumps they thought the balloon would hold and input this number. Each balloon inflates for 3 seconds and then either pops or stays intact depending on whether the participant's wager was above or below the predetermined explosion point for that balloon. If the balloon is pumped past its explosion point, it will pop, and the participant earns no points for that balloon. If the balloon is not pumped past the explosion point, the participant keeps the number of pumps as points. After each outcome, a new deflated balloon appears on the screen and points earned will be added to the total. Each balloon could earn a maximum of 128 points with an explosion point equally likely to occur on any given pump participant to the constraint that within each sequence of 10 balloons the average explosion point was on pump 64. The task will remain the same across the three studies and is a standardized online tool.

Description of the Need for the Information and Proposed Use of the Information:

NHTSA was established by the Highway Safety Act of 1970 (23 U.S.C. 101) to carry out a Congressional mandate to reduce deaths, injuries, and economic losses resulting from motor vehicle crashes on the Nation's highways. As part of this mandate, NHTSA is authorized to conduct research as a foundation for the development of traffic safety programs. As new vehicle technologies are developed, it is prudent to ensure that they do not create any unintended decrease in safety. The safe deployment of driving automation systems, particularly when deployed in mixed traffic where some vehicles are controlled by automation and some are controlled manually, requires an

understanding of how humans respond to and perceive different automation behavior. This work seeks to examine how drivers interact with driving automation systems in a wide sample of contexts and different levels of automation.

60-Day Notice:

A **Federal Register** Notice with a 60-day comment period soliciting comments on the following information collection was published on December 12, 2023 (88 FR 86202). Comments were received from the Insurance Institute for Highway Safety (IIHS).

NHTSA is grateful for the thorough and detailed review of the 60-day notice and the time and attention IIHS has given to ensure appropriate study parameters have been and will be taken into account. IIHS did not disagree with the sampling methodology or size, the design of the study or order of carryout, or the time or costs associated with the collection, so therefore no changes will be made to the study design or sampling methodology. The comments do not affect the burden estimates and therefore no changes will be made to the burden calculations.

IIHS recommended factoring experience, both as a driver and as a passenger where applicable, with each level of driving automation tested in the sampling approach and/or data analysis. We thank IIHS for this suggestion and agree about the importance of considering experience with automation in this project. We plan to collect information regarding participants' experience with automation, their understanding (*i.e.*, mental model) of automation, and their trust in vehicle automation technologies via forms included in this information collection: Pre-Drive Questionnaire, NHTSA Form 1746; In-Drive Questionnaire, NHTSA Form 1748; Post-Drive Questionnaire, NHTSA Form 1749. While we do not plan to include experience as a variable in our study design, we will be able to use the information collected to gain insight into differences in human-automation interaction based on prior experience and understanding.

IIHS commented that experimental manipulation of the simulated driving scenarios could be used to objectively evaluate different levels of situational awareness of the surrounding traffic and wayfinding ability and accuracy. They specifically mentioned reactive and proactive changes in behavior around object detection, trip planning, and navigation updating as important safety-related indicators of how people interact with their vehicles. We thank IIHS for this comment. We agree that variables other than vehicle kinematics should be

considered in measuring driver behavior in the test scenarios. To that end, we will collect information about driver glance behavior and visual attention from eye tracking in the simulator. We will also collect video data of both the driver and driving environment, such that we can code and understand how drivers respond to events involving vehicle automation. We will incorporate this feedback to also consider proactive changes in behavior, such as environmental scanning and latent hazard detection. We agree that trip planning and navigation may also yield valuable information from human-automation interactions, but these tasks are more difficult to replicate in the simulator and fall outside the scope of this project.

IIHS also recommended that NHTSA measure behind-the-wheel behavior, such as gaze and hand activity, because where the driver is looking and what their hands are doing will affect other behavior related to vehicle control. They noted that secondary activity, both driving-related and non-driving-related, is a normal phenomenon in driving with and without automation support and provided examples. IIHS wished for their inclusion in the set of dependent variables to better understand differences between participants and any changes in vehicle-kinematic behavior in the different driving scenarios. We completely agree with the suggestion. Our plan is to examine gaze, hand, and foot behavior during the study events. Previous work shows the importance of understanding (dis)engagement beyond looking at system status or takeover time. In this project, we plan to include different combinations of driving-related and non-driving-related secondary tasks (NDRTs). As IIHS suggests, we plan to examine driver interactions with automated vehicle interfaces, particularly in windows where automation encounters edge case or challenging situations in the study drives. The second and third studies will also include NDRTs and our analyses will consider outcomes such as attentional shifts between NDRTs and driving (or monitoring) as an outcome of different automated vehicle behaviors.

Related to the prior recommendation, IIHS recommended paying close attention to the driver management strategies incorporated in the design of the simulated vehicle. Design factors around driver monitoring, attention reminders, and last-resort countermeasures should be considered as they will shape the observable behind-the-wheel behavior, physical vehicle control, and interactions with

the simulated vehicle's interfaces. We completely agree and, to the extent possible, we will include management strategies that are representative of production or near-production systems. We will also include methods to set appropriate levels of expectation in our sample of drivers about the management strategy being used and the expectations for both the driver and the automated system.

IIHS also noted that the design philosophies currently behind Level 0 to 3 systems in production vary considerably among manufacturers to produce unique relationships between their customers and the technologies in their vehicles such that no two systems of a given level of driving automation should be considered the same. IIHS observed that these factors may produce confounds in the data if they are not considered in the design of the simulated systems under test. We agree with IIHS that the design of currently deployed automated systems varies considerably, and these design differences almost certainly have an impact on driver interactions. Our approach for the project will be to create systems in the simulator that are strong representations of some of the available technologies, understanding that other system designs could yield different driver-system interactions. Throughout our reporting on the project, we will clearly specify what design(s) our simulated system intends to replicate, what differences may exist, and the differences that exist from other systems not included in the simulator studies that are currently classified as within the same levels of automation. We will make clear what conclusions can and cannot be drawn about system design characteristics and be careful to avoid making general conclusions about a level of automation or type of automated system when there is variability in design that cannot be fully captured within the scope of the project.

Lastly, IIHS commented that how the simulated vehicle responds to different traffic conflicts or ambiguous driving scenarios in the study series will have ramifications on participant behavior. They noted that the realism of disruptions in system performance matters, both in terms of a sudden cessation of support as well as inappropriate system behavior. They were concerned that if care is not taken to ensure those disruptions are realistic and conform with what is technically possible and likely using what is known based on current implementations, it may affect participant behavior in ways that are outside the scope of the research and thus limit the

generalizability of the findings. We very much agree with the point that the situations and automated vehicle behaviors studied in this project need to match real-world situations and systems as closely as possible. We will use all available information to design the study scenarios to be representative of situations automation might encounter and might reasonably fall within a system's operational design domain. We will review information about available automated vehicle systems and make sure that the design of our study is consistent with the design of the systems.

We again thank IIHS for the thorough nature of their comments and will use them to improve the data collection.

Affected Public:

Individuals aged 18+ from Eastern Iowa and the surrounding areas who have volunteered to take part in driving studies will be contacted for participation. They will be randomized evenly by sex, though some imbalance will be permitted to be inclusive of individuals who do not identify on the gender spectrum or as a result of differences in how sex may be identified on drivers' licenses across States. Efforts

will be made to enroll a diverse age sample that broadly represents the age of the driving population and includes those at greater risk of crashing (e.g., less than 25 years of age and greater than 65 years of age). Businesses are ineligible for the sample and will not be contacted.

Estimated Number of Responses:
1,033 responses

To obtain the target number of 224 valid test participants. Assuming typical data loss rates for simulator testing with human participants, it is anticipated that 300 participants will need to be run in order to obtain 224 valid participant datasets. This will ensure sufficient statistical power in each of the three studies to detect differences between conditions.

Information for the three studies will be obtained in an incremental fashion to permit the determination of which individuals have the necessary characteristics for study participation. All interested candidates will complete the Eligibility Questionnaire once. From the subset of individuals found to meet the criteria in the Eligibility Questionnaire, a subset will be chosen with the goal of achieving a sample

providing a balance of sex to be scheduled for study participation and complete the appropriate informed consent once. Some imbalance will be allowed to be inclusive of all identities since not all individuals will identify on the gender spectrum. Participants will complete the Pre-Drive Questionnaire, one time, before a familiarization drive and the Wellness Questionnaire a total of three times to screen for simulator sickness. Participants who pass the screening will complete the remainder of the study procedures, including the In-Drive Questionnaire, the Post-Drive Questionnaire, and the Balloon Analogue Risk Task, each performed once.

Data collection will involve approximately 700 respondents for the Eligibility Questionnaire (with approximately 400 potentially meeting eligibility criteria) and 300 respondents for the Pre-Drive Questionnaire, Wellness Questionnaire, the Driving Behavior Assessment, the Post-Drive Questionnaire, and the Balloon Analogue Risk Task. A summary of the estimated numbers of individuals that will complete the noted question sets is provided in the following table.

ESTIMATED NUMBER OF TOTAL RESPONDENTS

Information collection	NHTSA form No.	Participants (i.e., respondents)
Eligibility Questionnaire	1742	700.
Informed Consent Study 1	1743	180.
Informed Consent Study 2	1744	60.
Informed Consent Study 3	1745	60.
Pre-Drive Questionnaire	1746	300 (180 Study 1, 60 Study 2, 60 Study 3).
Wellness Questionnaire	1747	300 (180 Study 1, 60 Study 2, 60 Study 3).
Driving Behavior Assessment (Pre-Drive PowerPoint Training, Familiarization Drive, Study Drive with In-Drive Questionnaire).	1748	300 (180 Study 1, 60 Study 2, 60 Study 3).
Post-Drive Questionnaire	1749	300 (180 Study 1, 60 Study 2, 60 Study 3).
Balloon Analogue Risk Task		300 (180 Study 1, 60 Study 2, 60 Study 3).

Frequency: One-time collection

Estimated Annual Burden Hours: The annual burden hours is estimated to be 301 hours per year.

The Eligibility Questionnaire (NHTSA Form 1742) is estimated to take 11 minutes (averaging those who complete the questionnaire and those who do not complete the questionnaire). The Informed Consent Study 1 (NHTSA Form 1743) is estimated to take 20 minutes. The Informed Consent Study 2 (NHTSA Form 1744) is estimated to take 20 minutes. The Informed Consent Study 3 (NHTSA Form 1745) is estimated to take 20 minutes. The Pre-Drive Questionnaire (NHTSA Form 1746) is estimated to take 15 minutes. The Wellness Questionnaire (NHTSA Form 1747) is estimated to take 5

minutes and is taken three times. The Driving Behavior Assessment (Pre-Drive PowerPoint Training, Familiarization Drive, Study Drive with In-Drive Questionnaire (NHTSA Form 1748) is estimated to take 80 minutes. The Post-Drive Questionnaire (NHTSA Form 1749) is estimated to take 20 minutes. The Balloon Analogue Risk Task (BART) is estimated to take 5 minutes.

The estimated annual time and cost burdens across all three study data collections are summarized in the table below. To calculate the opportunity cost associated with the forms and other relevant activities necessary for this collection of new information, NHTSA looked at average hourly earnings for employees on private nonfarm payrolls. NHTSA estimated the total opportunity

costs associated with these burden hours by looking at the average wage for total private employees on private nonfarm payrolls. The Bureau of Labor Statistics (BLS) estimates that the average hourly wage for this group is \$33.82.¹ Note that the costs in the table are opportunity costs and not labor costs, thus there is no burden cost associated with the study.

¹ See Table B–3 Average hourly and weekly earnings of all employees on private nonfarm payrolls by industry sector, seasonally adjusted, for August 2023, available at <https://www.bls.gov/news.release/empsit.t19.htm> (accessed October 3, 2023). See Table 1. Employer Costs for Employee Compensation by ownership (June 2023), available at <https://www.bls.gov/news.release/ecec.t01.htm> (accessed October 3, 2023).

ANNUAL BURDEN CALCULATIONS

Information collection	Number of respondents annual	Time per response (min)	Cost per response	Frequency of response	Burden (hours) annual	Opportunity cost (dollars) annual
Eligibility questionnaire	233	11	\$6.20	1	43	\$1,445
Informed Consent, Study 1	60	20	11.27	1	20	676
Informed Consent, Study 2	20	20	11.27	1	7	225
Informed Consent, Study 3	20	20	11.27	1	7	225
Pre-Drive Questionnaire	100	15	8.46	1	25	846
Wellness Questionnaire	100	5	2.82	3	25	846
Driving Behavior Assessment (Pre-Drive PowerPoint Training, Familiarization Drive, Study Drive with In-Drive Questionnaire)	100	80	45.09	1	133	4,509
Post-Drive Questionnaire	100	20	11.27	1	33	1,127
Balloon Analogue Risk Task	100	5	2.82	1	8	282
Annual Burden					301	10,181

Estimated Annual Burden Cost: \$0

The respondents will not incur any reporting or recordkeeping cost from the information collection. Respondents will incur a one-time cost for local travel to and from DSRI, which is estimated not to exceed approximately \$39.30 (based on the standard mileage rate for business-related driving in 2023 and a round trip distance of 60 miles²). These transportation costs are offset by participant compensation.

Public Comments Invited: You are asked to comment on any aspects of this information collection, including (a) 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; (b) 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; (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 information on respondents, including 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.

Authority: The Paperwork Reduction Act of 1995; 44 U.S.C. Chapter 35, as amended; 49 CFR 1.49; and DOT Order 1351.29A.

Cem Hatipoglu,

Associate Administrator, NHTSA Vehicle Safety Research.

[FR Doc. 2024-12735 Filed 6-10-24; 8:45 am]

BILLING CODE 4910-59-P

² <https://www.irs.gov/tax-professionals/standard-mileage-rates>; IR-2022-234 published December 29, 2022

DEPARTMENT OF THE TREASURY

Financial Crimes Enforcement Network

Agency Information Collection Activities; Proposed Renewal; Comment Request; Renewal Without Change of Due Diligence Programs for Correspondent Accounts for Foreign Financial Institutions and for Private Banking Accounts

AGENCY: Financial Crimes Enforcement Network (FinCEN), Treasury.

ACTION: Notice and request for comments.

SUMMARY: As part of its continuing effort to reduce paperwork and respondent burden, FinCEN invites comments on the proposed renewal, without change, of existing information collection requirements related to Bank Secrecy Act regulations that require certain banks, brokers or dealers in securities, futures commission merchants, introducing brokers in commodities, and mutual funds (each a “covered financial institution”) to establish and maintain due diligence programs for foreign financial institutions and for private banking accounts. The required due diligence programs include: appropriate, specific, risk-based, and, where necessary, enhanced policies, procedures, and controls reasonably designed to enable the covered financial institution to detect and report, on an on-going basis, money laundering conducted through or involving any correspondent accounts established, maintained, administered or managed by such covered financial institution in the United States for a foreign financial institution; and policies, procedures, and controls that are reasonably designed to detect and report any known or suspected money laundering or suspicious activity conducted through or involving any private

banking account that is established, maintained, administered, or managed in the United States by such covered financial institution. The due diligence programs are required to be part of covered financial institutions’ anti-money laundering programs. This request for comments is made pursuant to the Paperwork Reduction Act of 1995 (PRA).

DATES: Written comments are welcome and must be received on or before August 12, 2024.

ADDRESSES: Comments may be submitted by any of the following methods:

- **Federal E-rulemaking Portal:** <http://www.regulations.gov>. Follow the instructions for submitting comments. Refer to Docket Number FINCEN-2023-0011 and Office of Management and Budget (OMB) control number 1506-0046.

- **Mail:** Policy Division, Financial Crimes Enforcement Network, P.O. Box 39, Vienna, VA 22183. Refer to Docket Number FINCEN-2023-0011 and OMB control number 1506-0046.

Please submit comments by one method only. Comments will be reviewed consistent with the PRA and applicable OMB regulations and guidance. All comments submitted in response to this notice will become a matter of public record. Therefore, you should submit only information that you wish to make publicly available.

FOR FURTHER INFORMATION CONTACT: FinCEN’s Regulatory Support Section at 1-800-767-2825 or electronically at frc@fincen.gov.

SUPPLEMENTARY INFORMATION:

I. Statutory and Regulatory Provisions

The legislative framework generally referred to as the Bank Secrecy Act (BSA) consists of the Currency and Foreign Transactions Reporting Act of 1970, as amended by the Uniting and

Strengthening America by Providing Appropriate Tools Required to Intercept and Obstruct Terrorism Act of 2001 (USA PATRIOT Act)¹ and other legislation, including the Anti-Money Laundering Act of 2020 (AML Act).² The BSA is codified at 12 U.S.C. 1829b and 1951–1960 and 31 U.S.C. 5311–5314 and 5316–5336, and notes thereto, with implementing regulations at 31 CFR chapter X.

The BSA authorizes the Secretary of the Treasury (Secretary) to, *inter alia*, require financial institutions to keep records and file reports that are determined to have a high degree of usefulness in criminal, tax, or regulatory matters, risk assessments or proceedings, or in the conduct of intelligence or counter-intelligence activities to protect against terrorism, and to implement anti-money laundering/countering the financing of terrorism (AML/CFT) programs and compliance procedures.³ The authority of the Secretary to administer the BSA has been delegated to the Director of FinCEN.⁴

Section 312 of the USA PATRIOT Act added subsection (i) to 31 U.S.C. 5318 of the BSA. Section 312 mandates that each financial institution that establishes, maintains, administers, or manages a private banking account or a correspondent account in the United States for non-U.S. persons establish appropriate, specific, and, where necessary, enhanced, due diligence policies, procedures, and controls that are reasonably designed to detect and report instances of money laundering through those accounts. The regulations implementing the due diligence requirements for maintaining foreign correspondent accounts and private banking accounts are found at 31 CFR 1010.610 and 31 CFR 1010.620, respectively, and apply to covered financial institutions defined as certain banks, brokers or dealers in securities, futures commission merchants,

introducing brokers in commodities, and mutual funds.⁵

A. 31 CFR 1010.610—Due Diligence Programs for Correspondent Accounts for Foreign Financial Institutions

Under 31 CFR 1010.610(a), covered financial institutions are required to establish due diligence policies, procedures, and controls that include each of the following for any correspondent account established, maintained, administered, or managed in the United States for a foreign financial institution: (i) determining whether any such correspondent account is subject to enhanced due diligence (EDD) requirements specified in 31 CFR 1010.610(b); (ii) assessing the money laundering risks presented by each such correspondent account based on a consideration of all relevant factors;⁶ and (iii) applying risk-based procedures and controls to each such correspondent account reasonably designed to detect and report known or suspected money laundering activity, including a periodic review of the correspondent account activity sufficient to determine consistency with information obtained about the type, purpose, and anticipated activity of the account.

Under 31 CFR 1010.610(b), covered financial institutions are required to establish EDD policies, procedures, and controls when establishing, maintaining, administering, or managing a correspondent account in the United States for certain foreign banks, as described in 31 CFR 1010.610(c).⁷ The EDD shall include

⁵ 31 CFR 1010.605(e).

⁶ Relevant factors include, as appropriate: (i) the nature of the foreign financial institution's business and the markets it serves; (ii) the type, purpose, and anticipated activity of such correspondent account; (iii) the nature and duration of the covered financial institution's relationship with the foreign financial institution (and any of its affiliates); (iv) the AML and supervisory regime of the jurisdiction that issued the charter or license to the foreign financial institution, and, to the extent that information regarding such jurisdiction is reasonably available, of the jurisdiction in which any company that is an owner of the foreign financial institution is incorporated or chartered; and (v) information known or reasonably available to the covered financial institution about the foreign financial institution's AML record. 31 CFR 1010.610(a)(2).

⁷ The EDD procedures are required for any correspondent account maintained for a foreign bank that operates pursuant to: (i) an offshore banking license; (ii) a banking license issued by a foreign country that has been designated as non-cooperative with international AML principles or procedures by an intergovernmental group or organization of which the United States is a member and with which designation the U.S. representative to the group or organization concurs; or (iii) a banking license issued by a foreign country that has been designated by the Secretary as warranting special measures due to money laundering concerns. 31 CFR 1010.610(c).

procedures designed to ensure that the covered financial institution, at a minimum, takes reasonable steps to:

(1) Conduct enhanced scrutiny of such correspondent account to guard against money laundering and to identify and report any suspicious transactions in accordance with applicable law and regulation. This enhanced scrutiny shall reflect the risk assessment of the account and shall include, as appropriate: (i) obtaining and considering information relating to the foreign bank's AML program to assess the risk of money laundering presented by the foreign bank's correspondent account; (ii) monitoring transactions to, from, or through the correspondent account in a manner reasonably designed to detect money laundering and suspicious activity; (iii) if it is a payable-through account, obtaining information from the foreign bank about the identity of persons with authority to direct transactions through the correspondent account, as well as information about the sources and beneficial owners of funds or other assets in the payable-through account;⁸

(2) Determine whether the foreign bank for which the correspondent account is established or maintained in turn maintains correspondent accounts for other foreign banks that use the foreign correspondent account established or maintained by the covered financial institution and, if so, take reasonable steps to obtain information relevant to assess and mitigate money laundering risks associated with the foreign bank's correspondent accounts for other foreign banks, including, as appropriate, the identity of those foreign banks; and

(3) Determine, for any correspondent account established or maintained for a foreign bank whose shares are not publicly traded,⁹ the identity of each owner¹⁰ of the foreign bank and the nature and extent of each owner's ownership interest.

Under 31 CFR 1010.610(d), covered financial institutions are required to establish special procedures when due diligence or EDD cannot be performed, including when the covered financial institution should refuse to open the account, suspend transaction activity, file a suspicious activity report, or close the account.

⁸ See 31 CFR 1010.610(b)(1)(iii)(B).

⁹ The term "publicly traded" is defined at 31 CFR 1010.610(b)(3)(ii)(B).

¹⁰ The term "owner" is defined at 31 CFR 1010.610(b)(3)(ii)(A).

¹ USA PATRIOT Act, Public Law 107–56.

² The AML Act was enacted as Division F, sections 6001–6511, of the William M. (Mac) Thornberry National Defense Authorization Act for Fiscal Year 2021, Public Law 116–283, 134 Stat. 3388 (NDAA).

³ Section 358 of the USA PATRIOT Act expanded the purpose of the BSA by including a reference to reports and records "that have a high degree of usefulness in intelligence or counterintelligence activities to protect against international terrorism." See 12 U.S.C. 1829b(a). Section 6101 of the AML Act further expanded the purpose of the BSA to cover such matters as preventing money laundering, tracking illicit funds, assessing risk, and establishing appropriate frameworks for information sharing. See 31 U.S.C. 5311.

⁴ Treasury Order 180–01 (Jan. 14, 2020).

B. 31 CFR 1010.620—Due Diligence Programs for Private Banking Accounts

Under 31 CFR 1010.620, covered financial institutions are required to establish due diligence policies, procedures, and controls that, at a minimum, are designed to ensure that the covered financial institutions take reasonable steps to: (i) ascertain the identity of all nominal and beneficial owners of a private banking account;¹¹ (ii) ascertain whether any nominal or beneficial owner is a senior foreign political figure; (iii) ascertain the source(s) of funds deposited into a private banking account and the purpose and expected use of the account; and (iv) review the activity of the account to ensure that it is consistent with the information obtained about the client's source of funds and with the stated purpose and expected use of the account, as needed to guard against money laundering, and to report in accordance with applicable law and regulation, any known or suspected money laundering or suspicious activity conducted to, from, or through a private banking account.

Under 31 CFR 1010.620(c), in the case of a private banking account for which a senior foreign political figure is a nominal or beneficial owner, covered financial institutions are required to conduct enhanced scrutiny of the account that is reasonably designed to detect and report transactions that may involve the proceeds of foreign corruption.¹²

Under 31 CFR 1010.620(d), covered financial institutions are required to establish special procedures when appropriate due diligence cannot be performed, including when the covered financial institution should refuse to open the account, suspend transaction activity, file a suspicious activity report, or close the account.

II. Paperwork Reduction Act of 1995¹³

Title: Due diligence programs for correspondent accounts for foreign financial institutions and private

¹¹ Private banking account means an account (or any combination of accounts) maintained at a covered financial institution that: (i) requires a minimum aggregate deposit of funds or other assets of not less than \$1,000,000; (ii) is established on behalf of or for the benefit of one or more non-U.S. persons who are direct or beneficial owners of the account; and (iii) is assigned to, or is administered or managed by, in whole or in part, an officer, employee, or agent of a covered financial institution acting as a liaison between the covered financial institution and the direct or beneficial owner of the account. 31 CFR 1010.605(m).

¹² See 31 CFR 1010.620(c)(2) for the definition of the term "proceeds of foreign corruption."

¹³ Public Law 104–13, 44 U.S.C. 3506(c)(2)(A).

banking accounts (31 CFR 1010.610 and 31 CFR 1010.620).

OMB Control Number: 1506–0046.

Form Number: Not applicable.

Abstract: FinCEN is issuing this notice to renew the OMB control number for the regulations that require covered financial institutions to establish and maintain due diligence programs for correspondent accounts for foreign financial institutions and for private banking accounts.

Affected Public: Businesses or other for-profit institutions, and non-profit institutions.

Type of Review: Renewal without change of a currently approved information collection.

Frequency: As required.

Estimated Number of Respondents: 16,232 financial institutions.¹⁴

Estimated Recordkeeping Burden:

In Part 1 of this notice, FinCEN describes the distribution of the estimated number of covered financial institutions, by type. In Part 2, FinCEN proposes for review and comment a renewal of the calculation of the annual PRA burden that includes a scope and methodology similar to that used in the 2020 notice to renew this information collection.¹⁵

Part 1. Distribution of the Financial Institutions Covered by This Notice

The distribution of financial institutions, by type, covered by this notice is reflected in table 1 below:

TABLE 1—FINANCIAL INSTITUTIONS COVERED BY THIS NOTICE, BY TYPE

Type of institution	Count
Banks with a Federal functional regulator (FFR) ^a	9,800
Banks lacking an FFR ^b	600
Brokers or dealers in securities ^c	3,478
Mutual funds ^d	1,400
Futures commission merchants and introducing brokers in commodities ^e	954

¹⁴ Table 1 below breaks down the types of financial institutions covered by this notice.

¹⁵ See FinCEN, *Agency Information Collection Activities; Proposed Renewal; Comment Request; Renewal Without Change of Anti-Money Laundering Programs; Due Diligence Programs for Correspondent Accounts for Foreign Financial Institutions and for Private Banking Accounts*, 85 FR 61104 (Sept. 29, 2020).

TABLE 1—FINANCIAL INSTITUTIONS COVERED BY THIS NOTICE, BY TYPE—Continued

Type of institution	Count
Total	16,232

^a This estimate is based on call report data, as publicly available for download at the end of June 2023, from the Federal Financial Institutions Examination Council (FFIEC) for certain types of banks, savings associations, thrifts, trust companies (<https://cdr.ffiec.gov/public/pws/downloadbulkdata.aspx>) and from the NCUA for credit unions (<https://www.ncua.gov/analysis/credit-union-corporate-call-report-data>).

^b This estimate of active entries as of year-end 2023 incorporates data from both public and non-public sources, including: Call Reports; various State banking/financial institution regulators' websites and directories; the Federal Reserve Board of Governors' Master Account and Services database (<https://federalreserve.gov/paymentsystems/master-account-and-services-database-exisiting-access.htm>); and data from the OCIF (Oficina del Comisionado de Instituciones Financieras); and was derived in consultation with staff from the Internal Revenue Service's Small Business/Self-Employed Division.

^c Estimate based on December 2023 file downloaded from data maintained by the U.S. Securities and Exchange Commission's (SEC). SEC, Company Information About Active Broker-Dealers available at <https://www.sec.gov/help/foiadocsbdfioia> (accessed on Feb. 28, 2024).

^d This estimate of the number of active mutual funds as of year-end 2023 is based on Form N-CEN filings received by the SEC through January 20, 2023, as represented by data downloaded from SEC Open Data. SEC, Open Data, available at <https://www.sec.gov/dera/data/form-ncen-data-sets> (accessed Feb. 29, 2024).

^e The number of futures commissions merchants as of December 31, 2023, was obtained from data available through the Commodity Futures Trading Commission (CFTC). CFTC, Financial Data for Futures Commission Merchants, available at <https://www.cftc.gov/MarketReports/financialcmdata/index.htm> (accessed Mar. 1, 2024). To prevent double counting in burden estimates, 35 covered financial institutions that are also affected entities as broker-dealers were removed from the count; the count of introducing brokers in commodities as of year-end 2023 was provided by the CFTC.

In connection with a variety of initiatives FinCEN is undertaking to implement the AML Act, FinCEN intends to conduct, in the future, additional assessments of the PRA burden associated with BSA requirements.

Part 2. Annual PRA Burden and Cost

The scope of the annual PRA burden and cost estimates in this renewal is limited to maintaining and updating the due diligence programs as part of current AML program requirements for covered financial institutions. Due to the practical challenges of obtaining the total number of correspondent accounts maintained by covered financial

institutions for foreign financial institutions subject to general due diligence requirements, the number of correspondent accounts maintained for foreign banks subject to EDD requirements, and the number of private banking accounts, the scope of the annual PRA burden is limited to the annual burden of (i) maintaining and updating a due diligence program as part of the AML program for foreign correspondent accounts and private banking accounts, and (ii) securing approval of the program by an appropriate level of senior management.

FinCEN continues estimating the annual hourly burden of maintaining and updating the due diligence program for foreign correspondent accounts and private banking accounts at two hours per covered financial institution. This estimate covers the burden of (i) maintaining and updating the due diligence program to take into consideration any regulatory changes and any potential modifications required by changes in the types of foreign correspondent accounts or private banking accounts maintained, or by changes in the operations or

organizational structure of the foreign financial institutions for which a covered financial institution maintains accounts, as well as changes to the organizational structure of private banking accounts (one hour), and (ii) presenting the updated due diligence program to the appropriate level of senior management of the financial institution for approval (one hour).

FinCEN’s estimate of the annual PRA burden, therefore, is 32,464 hours, as detailed in table 2 below:

TABLE 2—BURDEN ASSOCIATED WITH UPDATING AND MAINTAINING THE DUE DILIGENCE PROGRAM AND OBTAINING SENIOR MANAGEMENT APPROVAL OF THE PROGRAM

Type of financial institution	Number of financial institutions (see table 1)	Time per financial institution (hours)		Aggregate burden hours per step		Total burden hours
		Maintenance	Approval	Maintenance	Approval	
Banks with an FFR	9,800	1	1	9,800	9,800	19,600
Banks without an FFR	600	1	1	600	600	1,200
Brokers or dealers in securities	3,478	1	1	3,478	3,478	6,956
Mutual funds	1,400	1	1	1,400	1,400	2,800
Futures commission merchants and introducing brokers in commodities	954	1	1	954	954	1,908
Total Burden Hours				16,232	16,232	32,464

FinCEN is utilizing the same fully-loaded composite hourly wage rate of \$106.30 utilized in the notice of proposed rulemaking (NPRM) entitled

Customer Identification Programs for Registered Investment Advisers and Exempt Reporting Companies, which was published on May 21, 2024.¹⁶

The total estimated cost of the annual PRA burden is \$3,450,923.20, as reflected in table 3 below:

TABLE 3—TOTAL COST OF THE ANNUAL PRA BURDEN

Steps	Hourly burden	Hourly cost	Total cost
Maintaining and updating the program	16,232	\$106.30	\$1,725,461.60
Board of directors/senior management approval of the program	16,232	106.30	1,725,461.60
Total Cost			3,450,923.20

Estimated Recordkeeping Burden: The average estimated annual PRA burden, measured in hours per respondent, is two hours (one burden hour to annually maintain and update the due diligence program, and one hour to annually obtain senior management approval of the due diligence program).

Estimated Number of Respondents: 16,232, as set out in table 1.

Estimated Total Annual Responses: 16,232 revised due diligence programs

for foreign correspondent accounts and private banking accounts annually; and 16,232 due diligences programs for foreign correspondent accounts and private banking accounts approved by senior management each year, as set out in table 2.

Estimated Total Annual Recordkeeping Burden: The estimated total annual PRA burden is 32,464 hours, as set out in table 2.

Estimated Total Annual Recordkeeping Cost: The estimated total annual PRA cost is \$3,450,923.20, as set out in table 3.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. Records required to be retained under the BSA must be retained for five years.

¹⁶ See FinCEN and SEC, *NPRM Customer Identification Programs for Registered Investment Advisers and Exempt Reporting Advisers*, 89 FR 44571 (May 21, 2024). Specifically, as set out on 89 FR 44590, table 1, footnote 1, the wage rate applied here is a general composite hourly wage (\$74.86), scaled by a private-sector benefits factor of 1.42 (\$106.30 = \$74.86 × 1.42), that incorporates the mean wage data (available for download at [https://](https://www.bls.gov/oes/tables.htm)

www.bls.gov/oes/tables.htm, “May 2022—National industry-specific and by ownership”) associated with the six occupational codes (11–1010: Chief Executives; 11–3021: Computer and Information Systems Managers; 11–3031: Financial Managers; 13–1041: Compliance Officers; 23–1010: Lawyers and Judicial Law Clerks; 43–3099: Financial Clerks, All Other) for each of the nine groupings of NAICS industry codes that FinCEN determined are most

directly comparable to its eleven categories of covered financial institutions as delineated in 31 CFR parts 1020 to 1030. The benefit factor is 1 plus the benefit/wages ratio, where as of Dec. 2023, Total Benefits = 29.6 and Wages and salaries = 70.4 (29.6/70.4 = 0.42) based on the private industry workers series data downloaded from <https://www.bls.gov/web/cecec/eccec-private-dataset.xlsx>, accessed Mar. 22, 2024.

Request for Comments: Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record. Comments are invited on: (i) 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; (ii) the accuracy of the agency's estimate of the burden of the collection of information; (iii) ways to enhance the quality, utility, and clarity of the information to be collected; (iv) 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 (v) estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Andrea M. Gacki,

Director, Financial Crimes Enforcement Network.

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Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Part 35

Building for the Future Through Electric Regional Transmission Planning
and Cost Allocation; Final Rule

DEPARTMENT OF ENERGY**Federal Energy Regulatory
Commission****18 CFR Part 35****[Docket No. RM21–17–000; Order No. 1920]****Building for the Future Through
Electric Regional Transmission
Planning and Cost Allocation****AGENCY:** Federal Energy Regulatory
Commission, Department of Energy.**ACTION:** Final order.

SUMMARY: The Federal Energy Regulatory Commission (Commission) revises the *pro forma* Open Access Transmission Tariff (OATT) to remedy deficiencies in the Commission's existing regional and local transmission planning and cost allocation requirements. In this final order, the

Commission requires transmission providers to conduct Long-Term Regional Transmission Planning that will ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs. The Commission also directs other reforms to improve coordination of regional transmission planning and generator interconnection processes, require consideration of certain alternative transmission technologies in regional transmission planning processes, and improve transparency of local transmission planning processes and coordination between regional and local transmission planning processes. These reforms are intended to ensure that existing regional and local transmission planning and cost allocation requirements are just,

reasonable, and not unduly discriminatory or preferential.

DATES: This final order is effective August 12, 2024.

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SUPPLEMENTARY INFORMATION:**Table of Contents**

Paragraph
Nos.

I. Introduction and Background	1
A. Historical Framework: Order Nos. 888, 890, and 1000	14
B. ANOPR and Technical Conference	20
C. Joint Federal-State Task Force on Electric Transmission	22
D. Notice of Proposed Rulemaking	26
E. High-Level Overview of NOPR Comments	36
F. Use of Terms	37
II. The Overall Need for Reform	47
A. NOPR Proposal	47
B. Comments	49
C. Commission Determination	85
1. The Transmission Investment Landscape Today	90
2. Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes	112
3. Benefits of Long-Term Regional Transmission Planning and Cost Allocation To Identify and Plan for Long-Term Transmission Needs	134
4. Conclusion	139
III. Long-Term Regional Transmission Planning	140
A. Requirement To Participate in Long-Term Regional Transmission Planning	140
1. NOPR Proposal	140
2. Comments	145
a. General Comments	145
b. Requests for Flexibility in Transmission Planning	151
c. Comments Regarding More Comprehensive Transmission Planning	163
d. Concerns Regarding Favoring Renewable Resources	172
e. Concerns Regarding Uncertainty, Over-Building, and Costs	176
f. Concerns Regarding Incentives for Resource Development	187
g. Comments Regarding Definition of Long-Term Regional Transmission Facility	189
h. Challenges to Commission Jurisdiction or Authority	190
i. Other Issues	215
j. Miscellaneous Concerns	217
3. Commission Determination	224
a. Participation in Long-Term Regional Transmission Planning	224
b. Definition of Long-Term Regional Transmission Facility	250
c. Legal Authority To Adopt Reforms for Long-Term Regional Transmission Planning	253
B. Development of Long-Term Scenarios	284
1. NOPR Proposal	284
2. Comments	286
a. General Comments	286
b. Applying Scenario Planning to Reliability and Economic Planning	296
3. Commission Determination	298
C. Long-Term Scenarios Requirements	307
1. Transmission Planning Horizon	307
a. NOPR Proposal	307
b. Comments	309
c. Commission Determination	344
2. Frequency of Long-Term Scenario Revisions	352

Paragraph
Nos.

a. NOPR Proposal	352
b. Comments	354
c. Commission Determination	377
3. Categories of Factors	387
a. Requirement To Incorporate Categories of Factors	387
b. Specific Categories of Factors	422
c. Treatment of Specific Categories of Factors	495
d. Stakeholder Process and Transparency	519
4. Number and Development of Long-Term Scenarios	538
a. NOPR Proposal	538
b. Comments	541
c. Commission Determination	559
5. Types of Long-Term Scenarios	564
a. NOPR Proposal	564
b. Comments	566
c. Commission Determination	575
6. Sensitivities for High-Impact, Low-Frequency Events	578
a. NOPR Proposal	578
b. Comments	580
c. Commission Determination	593
7. Specificity of Data Inputs	602
a. NOPR Proposal	602
b. Comments	606
c. Commission Determination	633
8. Identification of Geographic Zones	645
a. NOPR Proposal	645
b. Comments	650
c. Commission Determination	665
D. Evaluation of the Benefits of Regional Transmission Facilities	667
1. Requirement for Transmission Providers To Use a Set of Seven Required Benefits	669
a. NOPR Proposal	669
b. Comments	673
c. Commission Determination	719
2. Required Benefits	740
a. The Seven Required Benefits	740
3. Identification, Measurement, and Evaluation of the Benefits of Long-Term Regional Transmission Facilities	823
a. NOPR Proposal	823
b. Comments	824
c. Commission Determination	837
4. Evaluation of Transmission Benefits Over a Longer Time Horizon	843
a. NOPR Proposal	843
b. Comments	845
c. Commission Determination	859
5. Evaluation of the Benefits of Portfolios of Transmission Facilities	871
a. NOPR Proposal	871
b. Comments	872
c. Commission Determination	889
6. Issues Related to Use of Benefits	891
a. NOPR Proposal	891
b. Comments	892
c. Commission Determination	902
E. Evaluation and Selection of Long-Term Regional Transmission Facilities	904
1. Requirement To Adopt an Evaluation Process and Selection Criteria	904
a. NOPR Proposal	904
b. Comments	906
c. Commission Determination	911
2. Flexibility	919
a. NOPR Proposal	919
b. Comments	920
c. Commission Determination	924
3. Minimum Requirements	927
a. NOPR Proposal	927
b. Comments	930
c. Commission Determination	954
4. Role of Relevant State Entities	972
a. NOPR Proposal	972
b. Comments	973
c. Commission Determination	994
5. Voluntary Funding Opportunities	1003
a. NOPR Proposal	1003
b. Comments	1004
c. Commission Determination	1012
6. No Selection Requirement	1019

	Paragraph Nos.
a. NOPR Proposal	1019
b. Comments	1020
c. Commission Determination	1026
7. Other Issues	1029
a. Comments	1029
b. Commission Determination	1031
8. Reevaluation	1033
a. NOPR Proposal	1033
b. Comments	1035
c. Commission Determination	1048
F. Implementation of Long-Term Regional Transmission Planning	1062
1. NOPR Proposal	1062
2. Comments	1064
a. Comments on the Initial Timing Sequence	1064
b. Comments on Periodic Forums	1067
3. Commission Determination	1071
a. Initial Timing Sequence Implementation	1071
b. Periodic Forums	1075
IV. Coordination of Regional Transmission Planning and Generator Interconnection Processes	1076
A. Need for Reform and Overall Reform	1076
1. NOPR Proposal	1076
2. Comments	1079
a. On the Overall Reform	1079
b. Requesting Additional Reform	1081
c. Concerns With the Overall Reform	1085
d. Cost Allocation	1093
e. Interconnection Queue Gaming Considerations	1095
f. Miscellaneous	1098
3. Need for Reform	1100
4. Commission Determination	1106
B. Transmission Planning Process Evaluation	1122
1. NOPR Proposal	1122
2. Comments	1123
3. Commission Determination	1126
C. Qualifying Criteria	1130
1. NOPR Proposal	1130
2. Comments	1134
3. Commission Determination	1145
V. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices	1163
A. General Proposal	1163
1. NOPR Proposal	1163
2. Comments on General Proposal	1167
3. Need for Reform	1194
4. Commission Determination	1198
B. Specific Alternative Transmission Technologies	1217
1. NOPR Proposal	1217
2. Comments on Specific Technologies	1218
3. Commission Determination	1239
VI. Regional Transmission Cost Allocation	1248
A. Cost Allocation for Long-Term Regional Transmission Facilities	1248
1. Cost Allocation Methods for Long-Term Regional Transmission Facilities	1248
a. NOPR Proposal	1248
b. Comments	1252
c. Commission Determination	1291
2. Requirement that Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities	1308
a. NOPR Proposal	1308
b. Comments	1313
c. Commission Determination	1354
3. Proposals Relating to the Design and Operation of State Agreement Processes	1369
a. NOPR Proposal	1369
b. Comments	1371
c. Commission Determination	1402
4. Filing Rights Under the FPA	1422
a. Comments	1422
b. Commission Determination	1428
5. Time Period and Related Issues in the Long-Term Regional Transmission Planning Cost Allocation Processes for State-Negotiated Alternate Cost Allocation Method	1432
a. NOPR Proposal	1432
b. Comments	1436
c. Commission Determination	1456
B. Long-Term Regional Transmission Facility Cost Allocation Compliance With the Existing Six Order No. 1000 Regional Cost Allocation Principles	1458

	Paragraph Nos.
1. NOPR Proposal	1458
2. Comments	1459
a. General Proposal	1459
b. Comments Specific to a State Agreement Process	1467
3. Commission Determination	1469
C. Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities	1480
1. NOPR Proposal	1480
2. Comments	1482
a. Agree With Proposal	1482
b. Requests To Reflect the Full Breadth of Benefits in Cost Allocation Methods While Maintaining Flexibility	1491
c. Disagree With Proposal, Mostly Require Benefits	1492
d. Alignment of Benefits Between Transmission Planning and Cost Allocation	1497
e. Additional Benefits or Suggestions for Refinement	1502
3. Commission Determination	1505
D. Miscellaneous Cost Allocation Comments and Proposals	1516
1. Comments	1516
2. Commission Determination	1521
VII. Construction Work in Progress Incentive	1524
A. NOPR Proposal	1524
B. Comments	1525
1. Interest in the NOPR Proposal	1525
2. Concerns With the NOPR Proposal	1532
3. Interaction of the CWIP Incentive With the Abandoned Plant Incentive	1545
C. Commission Determination	1547
VIII. Exercise of a Federal Right of First Refusal in Commission-Jurisdictional Tariffs and Agreements	1548
A. NOPR Proposal	1548
B. Comments	1553
1. General Perspectives and Approach to Reform	1553
2. Comments on the NOPR's Joint Ownership Proposal	1560
C. Commission Determination	1563
IX. Local Transmission Planning Inputs in the Regional Transmission Planning Process	1565
A. Need for Reform	1565
1. NOPR	1565
2. Comments	1567
3. Commission Determination	1569
B. Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process	1578
1. NOPR Proposal	1578
2. Comments	1581
a. Interest in Enhanced Transparency of Local Transmission Planning Inputs	1581
b. Suggested Modifications to the NOPR Proposal	1586
c. Concern With the NOPR Proposal	1591
d. Specific Stakeholder Meeting Requirements	1601
e. Additional Issues	1613
3. Commission Determination	1625
a. Specific Stakeholder Meeting Requirements	1638
b. Additional Issues	1647
C. Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities	1649
1. Eligibility	1649
a. NOPR Proposal	1649
b. Comments	1652
c. Commission Determination	1677
2. Right of First Refusal	1693
a. NOPR Proposal	1693
b. Comments	1694
c. Commission Determination	1702
3. Cost Allocation	1710
a. NOPR Proposal	1710
b. Comments	1712
c. Commission Determination	1716
4. Miscellaneous	1723
a. Comments	1723
b. Commission Determination	1735
X. Interregional Transmission Coordination	1740
A. NOPR Proposal	1740
B. Comments	1744
C. Commission Determination	1751
XI. Compliance Procedures	1759
A. NOPR Proposal	1759
B. Comments	1761
C. Commission Determination	1768
XII. Information Collection Statement	1775
XIII. Environmental Analysis	1784
XIV. Regulatory Flexibility Act	1785

XV. Document Availability	1789
XVI. Effective Date and Congressional Notification	1792

I. Introduction and Background

1. In this final order, the Commission acts under section 206 of the Federal Power Act (FPA) to adopt reforms to its electric transmission planning and cost allocation requirements.¹ The reforms herein will remedy deficiencies in the Commission's existing regional and local transmission planning and cost allocation requirements to ensure that the rates, terms, and conditions for transmission service provided by public utility transmission providers (transmission providers)² remain just and reasonable and not unduly discriminatory or preferential. This final order builds upon Order No. 888, Order No. 890,³ and Order No. 1000,⁴ in which

¹ 16 U.S.C. 824e.

² Section 201(e) of the FPA, 16 U.S.C. 824(e), defines "public utility" to mean "any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter." As stated in the Order No. 888 *pro forma* Open Access Transmission Tariff (OATT), "transmission provider" is a "public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff." *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC*, 535 U.S. 1 (2002); *Pro forma* OATT section 1.1 (Definitions). The term "transmission provider" includes a public utility transmission owner when the transmission owner is separate from the transmission provider, as is the case in regional transmission organizations (RTO) and independent system operators (ISO).

³ *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, 118 FERC ¶ 61,119 (2007), *order on reh'g*, Order No. 890-A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007) (cross-referenced at 118 FERC ¶ 61,119), *order on reh'g and clarification*, Order No. 890-B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

⁴ *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), Order No. 1000-A, 77 FR 32184 (May 31, 2012), 139 FERC ¶ 61,132 (2012), *order on reh'g & clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

the Commission incrementally developed the requirements that govern regional transmission planning and cost allocation processes to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. Specifically, in this final order, we find that there is substantial evidence to support the conclusion that the existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential because the Commission's existing transmission planning and cost allocation requirements do not require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs;⁵ (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. Accordingly, we believe that it is necessary to revisit existing transmission planning and cost allocation requirements. We conclude that adopting the reforms of this final order, as previously contemplated in the notice of proposed rulemaking (NOPR),⁶ will remedy the identified deficiencies in existing regional and local transmission planning and cost allocation requirements, as discussed below, and will ensure the identification, evaluation, and selection, as well as the allocation of the costs, of more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

2. Specifically, the reforms adopted in this final order require transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.⁷ This final

order adopts specific requirements regarding how transmission providers must conduct Long-Term Regional Transmission Planning, including, among other things, the use of scenarios to identify Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs.

3. This final order also requires transmission providers to measure and use at least the seven specified benefits to evaluate Long-Term Regional Transmission Facilities as part of Long-Term Regional Transmission Planning. In addition, this final order requires transmission providers to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities and requires that this minimum 20-year benefit horizon be used both for the evaluation and selection of Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.⁸

4. This final order requires transmission providers to include in their OATTs an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs.

5. Further, this final order requires transmission providers to file one or more *ex ante* Long-Term Regional Transmission Cost Allocation Methods to allocate the costs of Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected. This final order further permits, but does not require,

region is one in which transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of a single regional transmission plan. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 160.

⁸ We recognize that some transmission planning regions may include Long-Term Regional Transmission Facilities, or a portfolio of such Facilities, in a regional transmission plan, but may not necessarily include these Facilities for purposes of cost allocation. *See* Order No. 1000, 136 FERC ¶ 61,051 at P 63. For purposes of this final order, unless otherwise noted, when referencing Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected, we intend "selected" to mean that those Facilities are selected in the regional transmission plan for purposes of cost allocation.

⁵ All capitalized terms are defined below. *Infra* Use of Terms section.

⁶ *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, 87 FR 26504 (May 4, 2022), 179 FERC ¶ 61,028 (2022) (NOPR); *see also* *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, 86 FR 40266 (July 27, 2021), 176 FERC ¶ 61,024 (2021) (advanced notice of proposed rulemaking (ANOPR)).

⁷ For purposes of this final order, and consistent with Order No. 1000, a transmission planning

transmission providers to adopt a State Agreement Process, wherein Relevant State Entities agree to such a State Agreement Process that would provide up to six months after selection for its participants to determine, and transmission providers to file, a cost allocation method for specific Long-Term Regional Transmission Facilities. This final order establishes a six-month time period (Engagement Period), during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables robust participation by Relevant State Entities.

6. This final order also requires transmission providers to include in their OATTs a process to provide Relevant State Entities and interconnection customers the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers' selection criteria. This final order requires transmission providers to include in their OATTs provisions that require transmission providers—in certain circumstances—to reevaluate Long-Term Regional Transmission Facilities that previously were selected.

7. In addition, this final order requires that transmission providers evaluate for potential selection in their existing Order No. 1000 regional transmission planning processes regional transmission facilities that will address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades⁹ originally identified

through the generator interconnection process.

8. This final order requires transmission providers in each transmission planning region to consider more fully the alternative transmission technologies of dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning and cost allocation processes.

9. This final order does not finalize the NOPR proposal to not permit transmission providers to take advantage of the recovery of 100% of construction work in progress for Long-Term Regional Transmission Facilities, and the Commission will instead continue to consider transmission incentives issues in other proceedings. This final order similarly does not finalize the NOPR proposal with respect to permitting the exercise of Federal rights of first refusal for selected transmission facilities, conditioned on the incumbent transmission provider with the Federal right of first refusal establishing joint ownership of the transmission facilities, and the Commission will instead continue considering the NOPR proposal and potential Federal right of first refusal issues in other proceedings.

10. This final order adopts the NOPR proposal to require transmission providers to adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to “right-size” replacement transmission facilities.

11. This final order requires transmission providers to revise their interregional transmission coordination processes to reflect the Long-Term Regional Transmission Planning reforms adopted in this final order. This final order also requires that transmission providers meet additional information sharing and transparency requirements with respect to their interregional transmission coordination processes.

12. This final order requires that each transmission provider submit a compliance filing within ten months of the effective date of this final order revising its OATT and other document(s) subject to the Commission's jurisdiction to

demonstrate that it meets the requirements of this final order, with the exception of those requirements adopted in the Interregional Transmission Coordination section in this final order. This final order requires that each transmission provider submit a compliance filing within 12 months of the effective date of this final order revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements adopted in this final order.

13. We recognize that transmission providers have ongoing efforts to address transmission planning and cost allocation. This final order is not intended to interfere with the potential progress represented by those efforts, and we encourage transmission providers to continue to innovate to improve their transmission planning and cost allocation processes.

A. Historical Framework: Order Nos. 888, 890, and 1000

14. Over the last several decades, the Commission has taken multiple significant actions on transmission planning and cost allocation, including issuing Order Nos. 888, 890, and 1000. In 1996, the Commission issued Order No. 888, which implemented open access to transmission facilities owned, operated, or controlled by a public utility and included certain minimum requirements for transmission planning. In 2007, the Commission issued Order No. 890 to address identified deficiencies in the *pro forma* OATT after more than 10 years of experience since Order No. 888. Among other OATT reforms, the Commission required all public utility transmission providers' local transmission planning processes to satisfy nine transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.¹⁰

15. In 2011, the Commission recognized the need for further transmission planning reforms with its issuance of Order No. 1000. The Commission based the reforms it adopted in Order No. 1000 on changes in the energy industry, its experience implementing Order No. 890, and a robust record developed through technical conferences and comments

⁹ The Commission's *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* Large Generator Interconnection Agreement (LGIA) provide that, “Network Upgrades shall mean the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.” See *Improvements to Generator Interconnection Procedures & Agreements*, Order No. 2023, 88 FR 61014 (Sept. 6, 2023), 184 FERC ¶ 61,054, at P 13 n.23, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*.

Order No. 2023–A, 89 FR 27006 (Apr. 16, 2024), 186 FERC ¶ 61,199 (2024). In this final order, we refer to network upgrades developed through the generator interconnection process as interconnection-related network upgrades.

¹⁰ Order No. 890, 118 FERC ¶ 61,119 at PP 418–601.

from a diverse range of stakeholders.¹¹ The Commission stated in Order No. 1000 that “the electric industry is currently facing the possibility of substantial investment in future transmission facilities to meet the challenge of maintaining reliable service at a reasonable cost.”¹² In establishing the requirements of Order No. 1000, the Commission found that the existing requirements of Order No. 890 were not adequate, noting that Order No. 1000 “expands upon the reforms begun in Order No. 890 by addressing new concerns that have become apparent in the Commission’s ongoing monitoring of these matters.”¹³ The Commission then enumerated multiple concerns that it had regarding existing transmission planning practices, including concerns about: (1) the lack of an affirmative obligation to develop a transmission plan evaluating if a regional transmission facility “may be more efficient or cost-effective than solutions identified in local transmission planning processes”; (2) the lack of a requirement to address Public Policy Requirements;¹⁴ (3) the Federal right of first refusal for incumbent transmission developers to build upgrades to their existing transmission facilities; (4) the lack of procedures to identify and evaluate the benefits of interregional transmission facilities; and (5) cost allocation for regional and interregional transmission facilities.¹⁵

16. Order No. 1000 included reforms intended to ensure that the transmission planning and cost allocation requirements embodied in the *pro forma* OATT could support the development of more efficient or cost-effective transmission facilities.¹⁶ The reforms in Order No. 1000 included: (1) regional transmission planning; (2) transmission needs driven by Public Policy Requirements; (3) nonincumbent transmission developer reforms; (4) regional and interregional cost

allocation, including a set of principles for each category of cost allocation; and (5) interregional transmission coordination. The reforms focused on the process by which transmission providers engage in regional transmission planning and the associated cost allocation rather than on the outcomes of the process.¹⁷

17. Among other regional transmission planning reforms in Order No. 1000, the Commission required that the following Order No. 890 transmission planning principles apply to regional transmission planning processes: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies.¹⁸

18. In addition, with respect to the Order No. 1000 reforms, the Commission made a distinction between a transmission facility “included” in a regional transmission plan and a transmission facility “selected.” A transmission facility selected in a regional transmission plan for purposes of cost allocation is a transmission facility that has been selected pursuant to a transmission planning region’s Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost allocation because it is a more efficient or cost-effective transmission facility needed to meet regional transmission needs. Both regional transmission facilities and interregional transmission facilities are eligible for potential “selection” in a regional transmission plan for purposes of cost allocation.¹⁹

19. Selected transmission facilities often will not comprise all of the transmission facilities that are included in a regional transmission plan.²⁰ Some transmission facilities are merely “rolled up” and listed in a regional transmission plan without going through an analysis at the regional level, and/or are merely considered for reliability implications upon a transmission system, and therefore, are not eligible for selection and regional cost allocation.²¹ For example, a local transmission facility is a transmission facility located solely within a

transmission provider’s retail distribution service territory or footprint that is not selected.²² Thus, a local transmission facility may be rolled up and “included” in a regional transmission plan for informational purposes, but it is not “selected.”

B. ANOPR and Technical Conference

20. In July 2021, the Commission issued the ANOPR²³ presenting potential reforms to improve the regional transmission planning and cost allocation and generator interconnection processes. In issuing the ANOPR, the Commission noted that, in part because more than a decade had passed since Order No. 1000, it was now an appropriate time to review its regulations governing regional transmission planning and cost allocation to determine whether reforms are needed to ensure Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.²⁴ The Commission noted that the electricity sector is transforming as the generation fleet shifts from resources located close to population centers toward resources that may often be located far from load centers. The Commission also highlighted the growth of new resources seeking to interconnect to the transmission system and that the differing characteristics of those resources are creating new demands on the transmission system. The Commission explained that ensuring just and reasonable Commission-jurisdictional rates during these changes, while maintaining grid reliability, remains the Commission’s priority in adopting requirements for the regional transmission planning and cost allocation and generator interconnection processes. As a result, the Commission issued the ANOPR to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly

¹¹ For purposes of this final order, and consistent with Order No. 1000, a stakeholder includes any party interested in the transmission planning processes. See Order No. 1000, 136 FERC ¶ 61,051 at P 151 n.143.

¹² *Id.* P 2.

¹³ *Id.* P 21.

¹⁴ Public Policy Requirements are requirements established by local, state, or Federal laws or regulations (*i.e.*, enacted statutes passed by the legislature and signed by the executive and regulations promulgated by a relevant jurisdiction, whether within a state or at the Federal level). *Id.* P 2. Order No. 1000–A clarified that Public Policy Requirements include local laws or regulations passed by a local governmental entity, such as a municipal or county government. Order No. 1000–A, 139 FERC ¶ 61,132 at P 319.

¹⁵ Order No. 1000, 136 FERC ¶ 61,051 at P 3.

¹⁶ *Id.* PP 11–12, 42–44; Order No. 1000–A, 139 FERC ¶ 61,132 at PP 3, 4–6.

¹⁷ Order No. 1000, 136 FERC ¶ 61,051 at P 12.

¹⁸ The Commission did not include the regional participation or cost allocation transmission planning principles with respect to regional transmission planning processes because those issues were addressed by other reforms in Order No. 1000. *Id.* P 151.

¹⁹ *Id.* P 63. A regional transmission facility and an interregional transmission facility are defined below. *Infra* Use of Terms section.

²⁰ Order No. 1000, 136 FERC ¶ 61,051 at P 63.

²¹ *Id.* PP 7, 226, 318.

²² *Id.* P 63. The Commission clarified in Order No. 1000–A that a local transmission facility is one that is located within the geographical boundaries of a public utility transmission provider’s retail distribution service territory, if it has one; otherwise, the area is defined by the public utility transmission provider’s footprint. In the case of an RTO/ISO whose footprint covers the entire region, a local transmission facility is defined by reference to the retail distribution service territories or footprints of its underlying transmission owning members. Order No. 1000–A, 139 FERC ¶ 61,132 at P 429.

²³ ANOPR, 176 FERC ¶ 61,024.

²⁴ *Id.* P 3.

discriminatory or preferential and that reliability is maintained.

21. On November 15, 2021, the Commission convened a staff-led technical conference (November 2021 Technical Conference or Technical Conference) to examine in detail issues and potential reforms related to regional transmission planning as described in the ANOPR. Specifically, the Technical Conference included three panels covering issues to consider in long-term scenarios, consideration of long-term scenarios in regional transmission planning processes, and identifying geographic zones with high renewable resource potential for use in regional transmission planning processes.²⁵ Following the Technical Conference, the Commission invited all interested persons to file comments to address issues raised during the Technical Conference.

C. Joint Federal-State Task Force on Electric Transmission

22. On June 17, 2021, the Commission established a Joint Federal-State Task Force on Electric Transmission (Task Force) to formally explore broad categories of transmission-related topics.²⁶ The Commission explained that the development of new transmission infrastructure implicates a host of different issues, including how to plan and pay for these facilities. Given that Federal and state regulators each have authority over transmission-related issues and given the impact of transmission infrastructure development on numerous different priorities of Federal and state regulators, the Commission determined that the topic was ripe for greater Federal-state coordination and cooperation.²⁷ The Task Force was composed of all sitting FERC Commissioners as well as representatives from 10 state commissions nominated by the National Association of Regulatory Utility Commissioners (NARUC), with two originating from each NARUC region.²⁸

23. The Task Force has convened multiple formal meetings with eight meetings held thus far to discuss

regional transmission planning and cost allocation issues, convening on November 10, 2021, February 16, 2022, May 6, 2022, July 20, 2022, November 15, 2022, February 15, 2023, July 16, 2023, and February 28, 2024.

24. The discussion at the November 2021 meeting was focused on incorporating state perspectives into regional transmission planning.²⁹ The February 2022 meeting included discussion of specific categories and types of transmission benefits that transmission providers should consider for the purposes of transmission planning and cost allocation.³⁰ The May 2022 meeting focused on barriers to the efficient, expeditious, and reliable interconnection of new resources.³¹ The July 2022 meeting focused on interregional transmission planning and transmission project development and the NOPR.³² The November 2022 meeting focused on regulatory gaps and challenges in oversight of transmission development.³³ The February 2023 meeting focused on the physical security of the Nation's transmission system, and featured guest speakers from the North American Electric Reliability Corporation and US DOE.³⁴ The July 2023 meeting focused on grid enhancing technologies, featuring a guest speaker from the Electric Power Research Institute.³⁵ The February 2024 meeting focused on transmission siting, featuring guest speakers from US DOE.³⁶

25. In light of the Task Force expiring three years from its first public meeting, *i.e.*, on November 10, 2024,³⁷ on March 21, 2024, the Commission established the Federal and State Current Issues Collaborative (Collaborative).³⁸ The Collaborative will be comprised of all

Commissioners, as well as representative from 10 state commissions. The Collaborative will provide a venue for Federal and state regulators to share perspectives, increase understanding, and where appropriate, identify potential solutions regarding challenges and coordination on matters that impact specific state and Federal regulatory jurisdiction.³⁹

D. Notice of Proposed Rulemaking

26. On April 21, 2022, the Commission issued the NOPR, proposing reforms focused on long-term regional transmission planning and cost allocation processes. In particular, the Commission proposed in the NOPR that transmission providers in each transmission planning region participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning.⁴⁰ The Commission also proposed to require that transmission providers develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning.⁴¹

27. The Commission proposed that transmission providers consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the relevant interconnection request(s).⁴²

28. The Commission proposed 12 benefits that transmission providers may consider in Long-Term Regional Transmission Planning and cost allocation processes.⁴³ The Commission stated that the list of potential benefits was neither mandatory nor exhaustive, and that pursuant to the proposal, transmission providers would have flexibility to propose which benefits to use as part of their Long-Term Regional Transmission Planning.⁴⁴

29. The Commission proposed, with regard to the selection of Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation, to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs: (1) transparent and not unduly

²⁵ Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection, Further Supplemental Notice of Technical Conference, Docket No. RM21-17-000 (issued Nov. 12, 2021) (attaching agenda).

²⁶ Joint Fed.-State Task Force on Elec. Transmission, 175 FERC ¶ 61,224, at PP 1, 6 (2021).

²⁷ *Id.* P 2.

²⁸ An up-to-date list of Task Force members, as well as additional information on the Task Force, is available on the Commission's website at: <https://www.ferc.gov/TFSOET>. Public materials related to the Task Force, including transcripts from public meetings, are available in the Commission's eLibrary in Docket No. AD21-15-000.

²⁹ Joint Fed.-State Task Force on Elec. Transmission, Notice of Meeting, Docket No. AD21-15-000 (issued Oct. 27, 2021) (attaching agenda).

³⁰ Joint Fed.-State Task Force on Elec. Transmission, Notice of Meeting, Docket No. AD21-15-000 (issued Feb. 2, 2022) (attaching agenda).

³¹ Joint Fed.-State Task Force on Elec. Transmission, Notice of Meeting, Docket No. AD21-15-000 (issued Apr. 22, 2022) (attaching agenda).

³² Joint Fed.-State Task Force on Elec. Transmission, Notice of Meeting, Docket No. AD21-15-000 (issued June 30, 2022) (attaching agenda).

³³ Joint Fed.-State Task Force on Elec. Transmission, Notice of Meeting, Docket No. AD21-15-000 (issued Nov. 1, 2022) (attaching agenda).

³⁴ Joint Fed.-State Task Force on Elec. Transmission, Notice of Meeting, Docket No. AD21-15-000 (issued Feb. 1, 2023) (attaching agenda).

³⁵ Joint Fed.-State Task Force on Elec. Transmission, Notice of Meeting, Docket No. AD21-15-000 (issued June 30, 2023) (attaching agenda).

³⁶ Joint Fed.-State Task Force on Elec. Transmission, Notice of Meeting, Docket No. AD21-15-000 (issued Feb. 13, 2024) (attaching agenda).

³⁷ Joint Fed.-State Task Force on Elec. Transmission, 175 FERC ¶ 61,224 at P 4.

³⁸ Joint Fed.-State Task Force on Elec. Transmission, 186 FERC ¶ 61,189 (2024).

³⁹ *Id.* PP 5-6.

⁴⁰ NOPR, 179 FERC ¶ 61,028 at PP 64, 68.

⁴¹ *Id.* P 84.

⁴² *Id.* P 166.

⁴³ *Id.* P 185.

⁴⁴ *Id.* P 184.

discriminatory criteria, which seek to maximize benefits to consumers over time without over-building transmission facilities, to identify and evaluate transmission facilities for potential selection that address transmission needs driven by changes in the resource mix and demand; and (2) a process to coordinate with the Relevant State Entities in developing such criteria.⁴⁵

30. The Commission proposed to require transmission providers to more fully consider the incorporation into transmission facilities of dynamic line ratings and advanced power flow control devices in regional transmission planning and cost allocation processes.⁴⁶

31. The Commission proposed to require, with regard to allocating the costs of Long-Term Regional Transmission Facilities, transmission providers to revise their OATTs to include: (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities; (2) a State Agreement Process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method; or (3) a combination thereof.⁴⁷ The Commission proposed to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.⁴⁸ The Commission proposed to require transmission providers to identify on compliance the benefits they will use in *ex ante* Long-Term Regional Transmission Cost Allocation Methods associated with Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.⁴⁹

32. The Commission further proposed to not permit transmission providers to take advantage of the allowance for inclusion of 100% of construction work in progress costs in rate base in certain circumstances for Long-Term Regional Transmission Facilities.⁵⁰

33. Finally, the Commission proposed to permit the exercise of Federal rights of first refusal for selected transmission

facilities, conditioned on the incumbent transmission provider with the Federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain proposed requirements described in the NOPR.⁵¹

34. The Commission also proposed to require transmission providers to revise the regional transmission planning process in their OATTs with additional provisions to enhance transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through that process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs.⁵² The Commission proposed to require transmission providers to evaluate whether transmission facilities operating at or above 230 kV that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be “right-sized” to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning.⁵³

35. The Commission further proposed to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes as needed) to provide for: (1) the sharing of information regarding their respective transmission needs identified in Long-Term Regional Transmission Planning, as well as potential transmission facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning.⁵⁴ Finally, the Commission proposed to require transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs

identified through Long-Term Regional Transmission Planning.⁵⁵

E. High-Level Overview of NOPR Comments

36. The Commission received a great many comments from a diverse set of parties in response to the NOPR.⁵⁶ One hundred and ninety-six parties, including Federal agencies, state regulatory commissions, state policy makers and other state representatives, ratepayer advocates, municipalities, RTOs/ISOs, RTO/ISO market monitors, transmission providers, transmission-dependent utilities, electric cooperatives, municipal power providers, independent power producers, transmission developers, generation trade associations, transmission trade associations, industry interest groups, consumer interest groups, energy policy and law interest groups, individual businesses, landowners, and individuals, filed initial comments that totaled over 15,000 pages with attachments. A similarly diverse set of 92 parties filed reply comments that totaled nearly 1,900 pages.

F. Use of Terms

37. Before turning to the detailed requirements of this final order, we note several of the key terms used herein. We further address the definitions of these terms, including any modifications to definitions proposed in the NOPR, in the relevant later sections of this final order.

38. For purposes of this final order, Long-Term Regional Transmission Planning means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.

39. For purposes of this final order, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final order, running

⁴⁵ *Id.* P 241.

⁴⁶ *Id.* P 272.

⁴⁷ *Id.* P 302.

⁴⁸ *Id.* P 303.

⁴⁹ *Id.* P 326.

⁵⁰ *Id.* P 333.

⁵¹ *Id.* P 351.

⁵² *Id.* P 400.

⁵³ *Id.* P 403.

⁵⁴ *Id.* P 427.

⁵⁵ *Id.* P 428.

⁵⁶ See appendix A for a list of commenters and the abbreviated names of commenters that are used in this final order.

scenarios and considering the enumerated categories of factors.⁵⁷

40. For purposes of this final order, Long-Term Scenarios are scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs.

41. For purposes of this final order, a Long-Term Regional Transmission Facility is a regional transmission facility⁵⁸ that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs.

42. For purposes of this final order, best available data inputs are data inputs that are timely, developed using best practices and diverse and expert perspectives, and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000, and reflect the list of factors that transmission providers account for in their Long-Term Scenarios.

43. For purposes of this final order, a Long-Term Regional Transmission Cost Allocation Method is an *ex ante* regional cost allocation method for one or more selected Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation.

44. For purposes of this final order, a Relevant State Entity is any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.

45. For purposes of this final order, a State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a

portfolio of such Facilities) before or no later than six months after they are selected.

46. For purposes of this final order, federally-recognized Tribes are those Tribes listed in the most recent notice provided by the Bureau of Indian Affairs and published in the **Federal Register**.⁵⁹

II. The Overall Need for Reform

A. NOPR Proposal

47. The Commission issued the NOPR on April 21, 2022, proposing to reform the *pro forma* OATT and the *pro forma* LGIA to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation requirements. The Commission stated that, over the last 25 years, it has undertaken a series of significant reforms to ensure that transmission planning and cost allocation processes result in Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.⁶⁰ The Commission noted that it has now been more than a decade since Order No. 1000—its last significant regional transmission planning and cost allocation rule—and that there is mounting evidence that its regional transmission planning and cost allocation requirements may be inadequate to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.⁶¹

48. The Commission found that, in particular, although transmission providers are required to participate in regional transmission planning and cost allocation processes under Order No. 1000, it was concerned that those processes may not be planning transmission on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand. The Commission stated that, as a result, the regional transmission planning and cost allocation processes that transmission providers adopted to comply with Order No. 1000 may not be identifying the more efficient or cost-effective transmission facilities.⁶² The Commission stated that it was concerned that the absence of sufficiently long-term, forward-looking, comprehensive transmission planning processes appears to be resulting in

piecemeal transmission expansion to address relatively near-term transmission needs, and that continuing with the status quo approach may cause transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. The Commission stated that this dynamic may result in transmission customers paying more than necessary to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof—either or both of which could potentially render Commission-jurisdictional rates unjust and unreasonable or unduly discriminatory or preferential. Based on the evidence, the Commission preliminarily concluded that revisions to its existing transmission planning and cost allocation requirements established in Order Nos. 890 and 1000 are necessary to ensure that Commission-jurisdictional services are provided at rates, terms, and conditions that are just and reasonable and not unduly discriminatory and preferential.⁶³

B. Comments

49. A significant majority of commenters, including transmission providers, transmission developers, transmission customers, members of Congress, states, state commissions, consumer advocates, trade associations, and public interest organizations, among others, agree that existing regional transmission planning and cost allocation processes need to be reformed.⁶⁴ Advanced Energy Buyers

⁶³ *Id.* PP 25, 27, 34–35.

⁶⁴ *See, e.g.,* Acadia Center and CLF Initial Comments at 1–2; ACEG Initial Comments at 11–12, 21–22; ACORE Initial Comments at 2–5; ACORE Supplemental Comments at 1; Advanced Energy Buyers Initial Comments at 2–3; AEE Initial Comments at 7–8; AEP Initial Comments at 1–3; Amazon Initial Comments at 1–2; Ameren Initial Comments at 1–2; American Municipal Power Initial Comments at 4; Anbaric Initial Comments at 1; Arizona Commission Initial Comments at 3–4; Avangrid Initial Comments at 5–6; BP Initial Comments at 3; Breakthrough Energy Initial Comments at 5–6; Breakthrough Energy Supplemental Comments at 1; Business Council for Sustainable Energy Initial Comments at 2–3; California Commission Initial Comments at 1–2; California Energy Commission Initial Comments at 1; CAISO Initial Comments at 1; City of New Orleans Council Initial Comments at 4, 7–9; Cross Sector Representatives Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 4–5; US Senators Supplemental Comments at 1; EEI Initial Comments at 4–5; ELCON Initial Comments at 4; Enel Initial Comments at 2, 7; ENGIE Initial Comments at 1–2; Entergy Initial Comments at 2–3; Environmental Legislators Caucus Supplemental Comments at 1; Evergreen Action Initial Comments at 1–3; Eversource Initial Comments at 1–2, 5–9; Exelon

⁵⁷ Further discussion on Long-Term Transmission Needs can be found below. *Infra* Development of Long-Term Scenarios subsection under the Long-Term Regional Transmission Planning section.

⁵⁸ For purposes of this final order, and consistent with Order No. 1000, a regional transmission facility is a transmission facility located entirely in one transmission planning region. An interregional transmission facility is a transmission facility that is located in two or more transmission planning regions. A local transmission facility is a transmission facility located solely within a transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation. Order No. 1000, 136 FERC ¶ 61,051 at PP 63, 482 n.374.

⁵⁹ *See, e.g., Indian Entities Recognized by and Eligible to Receive Servs. from the U.S. Bureau of Indian Affairs*, **Federal Register**, 89 FR 944 (Jan. 8, 2024).

⁶⁰ NOPR, 179 FERC ¶ 61,028 at P 24.

⁶¹ *Id.*

⁶² *Id.* PP 24–25.

note that the electric system is presently undergoing one of the most significant transformations in a century.⁶⁵ Other commenters agree that electric energy supply and demand is evolving quickly.⁶⁶ Clean Energy Buyers agree with the Commission that there is a need for reform to meet these drastic changes in the resource mix and load and to ensure continued reliability and cost-effective transmission service.⁶⁷

50. Many commenters argue that current regional transmission planning and cost allocation processes across the country are not ensuring efficient and cost-effective transmission development, are not satisfying the purposes of Order Nos. 890 and 1000, and are not meeting transmission needs at a reasonable cost. For example, several commenters assert that Order Nos. 890 and 1000 have not solved longstanding problems with regional

transmission planning and cost allocation.⁶⁸ Northwest and Intermountain claim that Order No. 1000 has been inadequate to meet transmission needs, particularly in the non-RTO/ISO West.⁶⁹ Michigan State Entities assert that the current lack of long-term transmission planning has led to significantly higher costs for residential ratepayers, costs that will increase without reforms.⁷⁰ SREA argues that reform is needed to correct the unintended consequences of Order No. 1000 in the Southeast, where transmission planning “has grown into an enormously elaborate and extremely expensive black box,” without any meaningful review by state regulatory bodies.⁷¹

51. PIOs assert that transmission owners can evade Order No. 1000 requirements through investments in local transmission projects, which has led to billions of dollars in excessive costs.⁷² PIOs explain that financial incentives drive utilities to upgrade their own systems at the expense of building a more integrated and robust transmission system to meet the needs and demands of the future.⁷³ PIOs observe that, between 2013 and 2017, about one-half of the approximately \$70 billion in aggregate transmission investments by Commission-jurisdictional transmission owners in RTO/ISO regions were approved outside of regional transmission planning processes or with limited stakeholder engagement.⁷⁴ Ohio Consumers add that since 2017, less than 25% of new transmission investments in Ohio have been associated with large regional

transmission projects needed for reliability or economic efficiency.⁷⁵ Competition Coalition argues that incumbent transmission owners have used reliability designations to justify projects with higher costs.⁷⁶

52. Citing to a report from Lawrence Berkeley National Laboratory, US DOE concludes that many existing regional transmission planning approaches are likely understating the economic value of new transmission. US DOE suggests that the need for increased transmission capacity to address persistent and worsening transmission congestion demonstrates that these processes may not fully anticipate present and future transmission needs.⁷⁷ In addition, US DOE notes the unfair burden on interconnection customers that must bear increasing costs, especially for interconnection-related network upgrades that provide system-wide benefits.⁷⁸ US DOJ and FTC agree that reforms are necessary to encourage needed regional and interregional transmission investment and that a larger, more integrated transmission system would improve resilience, promote competition, and lower costs for consumers.⁷⁹

53. Many commenters contend that inadequate regional transmission planning and cost allocation processes have resulted in, or are threatening to cause, unjust, unreasonable, and unduly discriminatory or preferential rates.⁸⁰ Michigan State Entities cite renewable energy curtailments, which limit the supply of energy that customers can access, and the lack of regional and interregional transmission lines, which limit the transfer of lower-priced power.⁸¹ New Jersey Commission asserts that better transmission planning

Initial Comments at 1–2; Grid United Initial Comments at 1–2; Handy Law Initial Comments at 1–7; Harvard ELI Initial Comments at 1; Illinois Commission Initial Comments at 3; Indicted PJM TOs Initial Comments at 1–2; Indicated US Senators and Representatives Initial Comments at 1; Intwest Initial Comments at 2–3; Invenery Initial Comments at 2, 5; ISO–NE Initial Comments at 2, 8–9; ISO/RTO Council Initial Comments at 2; Kansas Commission Initial Comments at 10–11; Massachusetts Attorney General Initial Comments at 3–6; Michigan Commission Initial Comments at 2, 4; Michigan State Entities Initial Comments at 3–4; Minnesota State Entities Initial Comments at 2–3; National Grid Initial Comments at 1, 6; National and State Conservation Organizations Initial Comments at 1; NESCOE Initial Comments at 2, 7, 14–15; New Jersey Commission Initial Comments at 1–2; New York Commission and NYSEDA Initial Comments at 1–3; NextEra Reply Comments at 1; Non-RTO NASUCA Initial Comments at 4–5; NYISO Initial Comments at 2–3; Onward Energy Initial Comments at 1–2; Ørsted Initial Comments at 2–3; Pattern Energy Initial Comments at 1; PacifiCorp and NV Energy Initial Comments at 2, 7–8; Pacific Northwest State Agencies Initial Comments at 1, 8; PG&E Initial Comments at 1; PIOs Initial Comments at 6–7; Policy Integrity Initial Comments at 1–2; Renewable Northwest Initial Comments at 3–4; RMI Supplemental Comments at 1–2; SPP Market Monitor Initial Comments at 3–4; SEIA Initial Comments at 2; Shell Initial Comments at 1, 9; US Senator Barrasso Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 2; Southeast PIOs Initial Comments at 1; SREA Initial Comments at 1; State Officials Supplemental Comments at 1; TAPS Initial Comments at 1–2; US DOE Initial Comments at 1–4; US DOJ and FTC Initial Comments 1, 5; Vermont State Entities Initial Comments at 2; Western State Representatives Initial Comments at 3–4; WIREs Initial Comments at 2, 5.

⁶⁵ Advanced Energy Buyers Initial Comments at 2.

⁶⁶ See, e.g., AEE Initial Comments at 1; Cross Sector Representatives Supplemental Comments at 1; Eversource Initial Comments at 5–8 (citing ISO–NE, 2020 *Regional Electricity Outlook*, at 35 (2020)); Indicated PJM TOs Initial Comments at 1–2; Kansas Commission Initial Comments at 2; Pattern Energy Initial Comments at 1; PG&E Initial Comments at 1; Policy Integrity Initial Comments at 2; Renewable Northwest Initial Comments at 5; State Agencies Initial Comments at 12–13; WIREs Initial Comments at 3.

⁶⁷ Clean Energy Buyers Initial Comments at 7.

⁶⁸ See, e.g., Acadia Center and CLF Initial Comments at 1; ACEG Initial Comments at 17–18, 20 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 3; NOPR, 179 FERC ¶ 61,028 at PP 24–25); AEE Initial Comments at 1–2; CARE Coalition Initial Comments at 3; NERC Initial Comments at 5; Massachusetts Attorney General Initial Comments at 5–6; Northwest and Intermountain Initial Comments at 6–7; Pine Gate Initial Comments at 8–10; PIOs Initial Comments at 2–3; Southeast PIOs Initial Comments at 7–9, 11, 16–17, 43–44; SPP Market Monitor Initial Comments at 3–4; SREA Reply Comments at 4; US DOE Initial Comments at 3–4, 7–8.

⁶⁹ Northwest and Intermountain Initial Comments at 6–7.

⁷⁰ Michigan State Entities Initial Comments at 1–2.

⁷¹ SREA Reply Comments at 4.

⁷² PIOs Initial Comments at 8 (citing Johannes P. Pfeifenberger et al., The Brattle Group, *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 19–20, and Section I (Apr. 2019) (Brattle Apr. 2019 Competition Report), https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf).

⁷³ *Id.* at 6–7.

⁷⁴ *Id.* at 9 (citing Brattle Apr. 2019 Competition Report at 4).

⁷⁵ Ohio Consumers Initial Comments at 5.

⁷⁶ Competition Coalition Initial Comments at 15–16.

⁷⁷ US DOE Initial Comments at 3–4.

⁷⁸ *Id.* at 7–8.

⁷⁹ US DOJ and FTC Initial Comments at 1, 5 (citing NOPR, 179 FERC ¶ 61,028 at P 6; P. R. Brown & A. Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 *Joule* 115, 115–134 (2021); Eric Larson et al., Princeton Univ., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, at 108 (Oct. 2021), <https://netzeroamerica.princeton.edu/the-report>).

⁸⁰ See, e.g., ACORE Initial Comments at 3, AEE Initial Comments at 27 (citing NOPR, 179 FERC ¶ 61,028 at PP 47, 55, 78; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56); CARE Coalition Initial Comments at 17; Certain TDUs Initial Comments at 2; Clean Energy Associations Initial Comments at 3, 7; Clean Energy Buyers Initial Comments at 10; Harvard ELI Initial Comments at 1; Massachusetts Attorney General Initial Comments at 5–6; New Jersey Commission Initial Comments at 1–2; PIOs Initial Comments at 6; SEIA Initial Comments at 2–3; Southeast PIOs Reply Comments at 2; US DOE Initial Comments at 2, 6–7.

⁸¹ Michigan State Entities Initial Comments at 3.

can reduce overall system costs by billions of dollars.⁸² Certain TDUs add that Commission action is essential now to ensure that necessary transmission expansion occurs in a way that protects customers from excessive costs and that results in just and reasonable transmission rates.⁸³ CARE Coalition argues that the Commission's current failure to require transmission planners to internalize siting-related costs and risks results in unjust, unreasonable, and unduly discriminatory or preferential rates.⁸⁴ In a similar vein, Ørsted and Massachusetts Attorney General claim that failure to proactively plan for offshore wind generation buildout could lead to transmission rates that are unjust, unreasonable, and unduly discriminatory or preferential.⁸⁵

54. Several commenters agree with the Commission's concerns that the expansion of the high-voltage transmission system is increasingly occurring outside of the regional transmission planning process through other mechanisms such as the generator interconnection process, which results in piecemeal transmission development.⁸⁶ AEE agrees that limited development of regional transmission facilities, increased spending on local transmission projects, and backlogged interconnection queues all show that the existing regional transmission planning requirements are not sufficient to meet customers' transmission needs.⁸⁷ Likewise, Exelon argues that relying on interconnection studies as the primary transmission planning method results in piecemeal and inefficient transmission investment.⁸⁸ PIOs add that many generation developers have to bear the full costs of transmission upgrades, which leads to interconnection request withdrawals, inefficiencies, and higher system-wide costs.⁸⁹ In addition, Clean Energy States note that interconnection queues are extremely large and that the current one-plant-at-a-time approach to transmission upgrades drives up costs

and misses opportunities for improvements to the system as a whole.⁹⁰

55. Non-RTO NASUCA agrees with the Commission that Long-Term Regional Transmission Planning is necessary to help alleviate generation interconnection issues.⁹¹ According to Harvard ELI, current transmission planning processes have failed to address backlogged interconnection queues and operational challenges that are best addressed at the regional level, as well as to include inexpensive technologies that can increase transmission capacity.⁹²

56. ACEG argues that there is no evidence that any regional reliability or economic transmission planning performed in non-RTO/ISO regions, like the Southeastern Regional Transmission Planning region (SERTP), is equal to or superior to the techniques or outcomes in the NOPR.⁹³ ACEG further contends that, instead, most new transmission facilities built since Order No. 1000 have been built for local transmission needs, thereby resulting in less efficient and cost-effective transmission development that does not address the larger needs of the transmission system for reliability and resilience.⁹⁴ Relatedly, SREA states that no state fully participates in SERTP, and that instead, each state in the Southeast uses its own state planning process, with no platform for states to collaborate. As a result, SREA argues that "transmission planning in the Southeast has many holes and is threadbare."⁹⁵ SREA catalogs deficiencies in many Southeastern states' planning processes, including a lack of transparency.⁹⁶

57. Western PIOs argue that, outside of CAISO, transmission planning in the West is ineffective.⁹⁷ Specifically, Western PIOs assert that Western transmission planning groups have not developed new transmission projects using their Order No. 1000 transmission planning processes, but have instead built transmission projects that their utility members have already proposed.⁹⁸ Relatedly, SEIA argues that "non-RTO areas do not engage in sufficient or transparent transmission planning," and that transmission planning in non-RTO/ISO regions is

exclusionary, based on inconsistent and inaccurate data, and disjointed.⁹⁹ More broadly, NRECA contends that incumbent investor-owned utilities control transmission planning, and that some incumbent investor-owned utilities develop transmission without transparency, leading to disparities in transmission rates in different RTO/ISO local zones.¹⁰⁰

58. Several commenters specify other reasons that transmission planning reforms are needed.¹⁰¹ Americans for Fair Energy Prices agree with PIOs that there is a need for regional transmission planning instead of the balkanized process that currently exists.¹⁰² DC and MD Offices of People's Counsel assert that the NOPR provides a once-in-a-generation opportunity to meet the energy transition in a just, equitable, efficient, reliable, and resilient fashion by recognizing the benefits of long-term transmission planning and developing rules that incorporate those broad benefits. DC and MD Offices of People's Counsel state that current transmission planning processes do not fully consider all of the benefits of transmission development, including enhanced reliability and resilience that will serve as a necessary bulwark against disruptions caused by extreme weather.¹⁰³ ACEG argues that current transmission planning processes have not led to investment in interregional transmission capacity, and that more interregional transmission capacity could have avoided some of the \$25 billion to \$70 billion in yearly costs caused by severe weather events.¹⁰⁴ EEI states that robust transmission development will provide a host of benefits for customers, including greater resilience, enhanced system reliability, and cost-savings from greater access to low-cost resources.¹⁰⁵ Some commenters emphasize the importance of the Commission taking prudent action to remedy deficiencies in the Commission's existing regional transmission planning and cost

⁸² New Jersey Commission Initial Comments at 3–9.

⁸³ Certain TDUs Initial Comments at 2.

⁸⁴ CARE Coalition Initial Comments at 17.

⁸⁵ Massachusetts Attorney General Initial Comments at 5; Ørsted Initial Comments at 3–5.

⁸⁶ See, e.g., Acadia Center and CLF Initial Comments at 3–4; Anbaric Initial Comments at 5; Clean Energy Associations Initial Comments at 4–7; Exelon Initial Comments at 1–2, 5; Joint Consumer Advocates Initial Comments at 5; Non-RTO NASUCA Initial Comments at 4; Ørsted Initial Comments at 4–5; Pine Gate Initial Comments at 8–10; SEIA Initial Comments at 2; see also AEP Initial Comments at 8.

⁸⁷ AEE Initial Comments at 1–2 (citing NOPR, 179 *FERC* ¶ 61,028 at PP 47–55).

⁸⁸ Exelon Initial Comments at 5.

⁸⁹ PIOs Initial Comments at 9–10.

⁹⁰ Clean Energy States Initial Comments at 2.

⁹¹ Non-RTO NASUCA Initial Comments at 4.

⁹² Harvard ELI Initial Comments at 1.

⁹³ ACEG Reply Comments at 9 (citing Alabama Commission Initial Comments at 2–3; Southern Initial Comments at 5–6, Ex. 2 at 2–3).

⁹⁴ *Id.* at 9–10 (citing PIOs Initial Comments at 7).

⁹⁵ SREA Reply Comments at 4.

⁹⁶ *Id.* at 5–18.

⁹⁷ Western PIOs Initial Comments at 4–28.

⁹⁸ *Id.* at 28.

⁹⁹ SEIA Reply Comments at 5–6 (citing Southern Initial Comments at 13–14).

¹⁰⁰ NRECA Initial Comments at 15–16.

¹⁰¹ See, e.g., Americans for Fair Energy Prices Reply Comments at 5; SREA Reply Comments at 4.

¹⁰² Americans for Fair Energy Prices Reply Comments at 5 (citing PIOs Initial Comments at 34).

¹⁰³ DC and MD Offices of People's Counsel Reply Comments at 1–2.

¹⁰⁴ ACEG Initial Comments at 21–22 (citing Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather*, at 1–3, 12 (July 2021) (Grid Strategies July 2021 Extreme Weather Report)).

¹⁰⁵ EEI Supplemental Comments at 1.

allocation requirements,¹⁰⁶ and to strengthen electric reliability and resilience, while controlling costs.¹⁰⁷

59. Several commenters argue that the need to reform transmission planning includes addressing environmental justice and equity issues.¹⁰⁸ Center for Biological Diversity states that energy justice and environmental justice considerations are appropriately included in transmission planning.¹⁰⁹ Center for Biological Diversity further asserts that it is within the Commission's authority to consider these costs and benefits, as the benefits of decarbonization and related energy justice objectives will be far greater than the costs.¹¹⁰ Grand Rapids NAACP, CARE Coalition, and PIOs argue that to ensure just, reasonable, and nondiscriminatory rates, transmission planning must consider energy equity and environmental justice.¹¹¹ Grand Rapids NAACP further argues that high energy burdens can be unjust, unreasonable, and unduly discriminatory or preferential.¹¹² Grand Rapids NAACP argues that the Commission's duty under the FPA to promote the public interest requires it to ensure that energy justice and equity considerations are included in transmission planning processes.¹¹³ WE ACT relatedly argues that, due to under-investment, the transmission system is unreliable and vulnerable to extreme

weather events, which is both a reliability and environmental justice issue because communities of color and low-income communities are more susceptible to power outages during extreme weather.¹¹⁴

60. Advanced Energy Buyers state that failure to prepare the grid for the energy transition would be problematic for three primary reasons: (1) insufficient transmission investment will leave customer cost savings on the table; (2) lack of available transmission capacity will constrain its members' ability to meet decarbonization and clean energy goals; and (3) failure to plan and build adequate transmission will hamper the transition to a cleaner and more reliable electric grid.¹¹⁵ New Jersey Commission contends that the lack of holistic multi-driver transmission planning is inflating consumers' electricity costs by billions of dollars every year.¹¹⁶ Northwest and Intermountain explain that due to insufficient transmission capacity from renewable rich zones, utilities must attempt to meet their renewable energy policy targets with new resources that are close to load but more expensive, less reliable, and less efficient than more distant alternatives, even considering the potential costs of transmission expansion.¹¹⁷ Clean Energy Associations add that the lack of transmission capacity imposes real and demonstrable costs today, as evidenced by geographic differences in real-time power prices, and that the lack of robust and proactive transmission planning rules renders current rates unjust, unreasonable, and unduly discriminatory or preferential.¹¹⁸

61. Southeast PIOs contend that the "snowballing" inefficiencies created by numerous small-scale transmission "band-aids" result in unjust, unreasonable, and unduly discriminatory or preferential rates, and that reforms are particularly needed in the Southeast, where there is minimal utility coordination and a balkanized transmission system.¹¹⁹ According to ACEG, short-term, piecemeal transmission planning is unlikely to

identify the more efficient or cost-effective solutions to transmission needs and thus will result in unjust, unreasonable, and unduly discriminatory or preferential rates.¹²⁰

62. Many commenters argue that reforms are necessary to meet state policy goals¹²¹ and that greater state involvement or consideration of state policies is needed to avoid transmission planning inefficiencies.¹²² For example, ACORE cites a recent National Renewable Energy Laboratory (NREL) report highlighting the need for new transmission to aid in achieving zero carbon goals.¹²³ NextEra opines that the passage of the Inflation Reduction Act of 2022 will increase the demand for renewables and drive corresponding demands on the transmission system.¹²⁴ Pacific Northwest State Agencies argue that reforms are critical to successfully achieving their respective state clean energy laws and policies and to ensuring that there is sufficient clean, safe, reliable, and affordable energy.¹²⁵ Michigan State Entities note that some states may pursue aggressive renewable energy portfolio standards, and others may have no such requirements, but these policy choices will inevitably affect the price and reliability of energy for all customers across the states in question and that not planning for that reality imposes costs on unwilling customers.¹²⁶

¹⁰⁶ US Senators Supplemental Comments at 1; Senator Whitehouse Supplemental Comments at 2.

¹⁰⁷ US Senator Barrasso Supplemental Comments at 1–2.

¹⁰⁸ See, e.g., CARE Coalition Initial Comments at 2; Center for Biological Diversity Initial Comments at 20–24; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Grand Rapids NAACP Initial Comments at 20–21; Massachusetts Attorney General Initial Comments at 53–54 (citing Massachusetts Attorney General ANOPR Initial Comments at 32–34); Montclair Congregation Supplemental Comments at 1; NESCOE Reply Comments at 8–9; New England for Offshore Wind Initial Comments at 5; PIOs Reply Comments at 11–17; US DOE Initial Comments at 9; WE ACT Initial Comments at 1–2.

¹⁰⁹ Center for Biological Diversity Initial Comments at 20–24 (citing Pacific Northwest National Laboratory & Sandia National Laboratories, *Advancing Energy Equity in Grid Planning* (Apr. 2022), <https://netl.doe.gov/sites/default/files/netl-file/Advancing%20Energy%20Equity%20in%20Grid%20Planning.pdf>; Office of Energy Justice and Equity, US DOE, *Justice40 Initiative*, <https://www.energy.gov/diversity/justice40-initiative>).

¹¹⁰ *Id.* at 23 (citing *Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 942 (8th Cir. 2020)).

¹¹¹ Grand Rapids NAACP Reply Comments at 4 (citing 16 U.S.C. 824(a); *Re Nat'l Ass'n for the Advancement of Colored People, Inc.*, 95 P.U.R.3d 357 (F.P.C. 1972), *vacated and remanded sub nom. NAACP v. FPC*, 520 F.2d 432 (D.C. Cir. 1975), *aff'd*, 425 U.S. 662 (1976)); CARE Coalition Initial Comments at 2; PIOs Reply Comments at 14.

¹¹² *Id.* at 20–21.

¹¹³ *Id.* at 17–19.

¹¹⁴ WE ACT Initial Comments at 1–2.

¹¹⁵ Advanced Energy Buyers Initial Comments at 3.

¹¹⁶ New Jersey Commission Initial Comments at 2–9.

¹¹⁷ Northwest and Intermountain Initial Comments at 6.

¹¹⁸ Clean Energy Associations Initial Comments at 5 (citing Dev Millstein et al., Lawrence Berkeley National Laboratory, *Empirical Estimates of Transmission Value Using Locational Marginal Prices*, at 3 (Aug. 2022), https://eta-publications.lbl.gov/sites/default/files/lbnlempirical_transmission_value_study-august_2022.pdf (LBNL Aug. 2022 Transmission Value Study)).

¹¹⁹ Southeast PIOs Reply Comments at 1–2.

¹²⁰ ACEG Initial Comments at 21.

¹²¹ See, e.g., Acadia Center and CLF Initial Comments at 1; ACORE Reply Comments at 1; Breakthrough Energy Initial Comments at 5–6; Business Council for Sustainable Energy Initial Comments 2–3; Illinois Commission Initial Comments at 3–4; ISO–NE Initial Comments at 2; Michigan State Entities Initial Comments at 2–3; National Grid Initial Comments at 6–7; NESCOE Initial Comments at 9–10, 15–16; NextEra Reply Comments at 5, 25; Northwest and Intermountain Initial Comments at 5–6; Ørsted Initial Comments at 1–3; Pacific Northwest State Agencies Initial Comments at 1; PacifiCorp and NV Energy Initial Comments at 10–11; State Agencies Initial Comments at 16–17; Vermont Electric and Vermont Transco Initial Comments at 2; Western State Representatives Initial Comments at 3.

¹²² See, e.g., AEE Reply Comments at 3–4; California Democratic Representatives Supplemental Comments at 1–2; US Senators Supplemental Comments at 1 (citing to National Academies of Sciences, Engineering, and Medicine, *Accelerating Decarbonization in the United States: Technology, Policy, and Societal Dimensions* (2023)); Maryland Energy Admin Initial Comments at 1; North Carolina Commission and Staff Initial Comments at 2, 4; PJM States Initial Comments at 1; SREA Reply Comments at 4.

¹²³ ACORE Reply Comments at 1 (citing Paul Denholm, et al., NREL, *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035* (Sept. 2022), <https://www.nrel.gov/docs/fy22osti/81644.pdf>).

¹²⁴ NextEra Reply Comments at 5, 25.

¹²⁵ Pacific Northwest State Agencies at 1.

¹²⁶ Michigan State Entities Initial Comments at 2–3.

63. PacifiCorp and NV Energy similarly assert that the need for reform in the West is driven by the diverse policy priorities in its six-state transmission system, and they note that decisions are subject to state oversight and the participation of disparately situated transmission providers without inclination or authority to accept any cost allocation.¹²⁷ National Grid asserts that ISO New England's (ISO-NE) 2050 Transmission Study demonstrates a direct connection between state laws and requirements to meet clean energy goals and the need for new and expanded transmission facilities.¹²⁸ Indicated PJM TOs add that maintaining a reliable and resilient transmission system requires forward-looking assessments informed by evolving public policy, changing generation mix and demand patterns, and stakeholder input.¹²⁹

64. Maryland Energy Administration contends that Maryland has experienced unfair and costly consequences of inadequate consultation with state authorities in regional transmission planning processes.¹³⁰ AEE argues that if current transmission planning processes fail to incorporate factors such as state laws, corporate targets, and retail demand, then transmission needs will be unmet, risking unjust, unreasonable, and unduly discriminatory or preferential rates.¹³¹

65. Many commenters argue that, based on the record, the Commission has an obligation under the FPA to take action to ensure that transmission planning and cost allocation results in rates that are just and reasonable and not unduly discriminatory.¹³² ACEG states that the Commission's broad authority to remedy unduly discriminatory behavior pursuant to FPA section 206 applies to transmission planning and cost allocation, as the U.S. Court of Appeals for the District of Columbia Circuit held in *South Carolina Public Service Authority v. FERC*.¹³³ PIOs contend that the Commission is

required by the FPA to use its authority to address market abuses and undue discrimination that have led to unjust, unreasonable, and unduly discriminatory or preferential rates for consumers, who bear the costs of inefficiencies in the current transmission planning process.¹³⁴

66. Southeast PIOs assert that the NOPR adequately demonstrated that existing regional transmission planning processes have intrinsic flaws, making the integrated resource planning and request for proposal processes ill-equipped to efficiently address changes in the resource mix and demand.¹³⁵ Specifically, Southeast PIOs cite the following preliminary findings from the NOPR: (1) existing transmission planning processes utilize a limited planning horizon; (2) many transmission planning processes provide an inaccurate portrayal of the comparative benefits of different transmission facilities; and (3) rapid changes to the generation fleet and demand are creating increasingly urgent transmission needs.¹³⁶

67. Southeast PIOs cite the finding in *South Carolina Public Service Authority v. FERC* that the threshold of substantial evidence could be met without "empirical evidence" as long as the Commission provides evidence based on "reasonable economic propositions."¹³⁷ Southeast PIOs also note that *South Carolina Public Service Authority v. FERC* upheld the Commission's findings in Order No. 1000, which were based on (1) a threat to just and reasonable rates from existing regional transmission planning and cost allocation practices, (2) significant changes in the industry driven by increases in renewable energy resources, and (3) recent increases in transmission investment.¹³⁸ Moreover, Southeast PIOs note that findings need not be region-specific, as the "Commission may rely on generic or general findings of a systemic problem to support imposition of an industry-wide solution."¹³⁹

68. ACEG similarly asserts that the Commission has shown the need for transmission planning reform based on findings that existing transmission

planning requirements do not adequately identify transmission needs driven by changes in the resource mix and demand, and that failure to identify such needs causes customers to pay for less efficient or cost-effective transmission investments.¹⁴⁰ Relatedly, ACEG argues that pursuing region-specific solutions will lead to siloed and disjunctive transmission planning policies that will not solve the problems facing the Nation's electric transmission system.¹⁴¹

69. Colorado Consumer Advocate and Joint Consumer Advocates aver that the Commission has a statutory duty under the FPA to reform current regional transmission planning processes because they lack transparency, coordination, and openness, and because they create opportunities for monopoly transmission developers to exert dominant influence and promote their own economic self-interest at customers' and other stakeholders' expense.¹⁴² According to New Jersey Commission, current transmission planning processes are inefficient and unnecessarily burden ratepayers with excessive costs without providing additional benefits. New Jersey Commission contends that those processes are therefore per se unjust and unreasonable, and that the Commission thus has FPA section 206 authority to require that transmission providers employ practices like long-term, holistic, multi-driver transmission planning.¹⁴³

70. Similarly, Harvard ELI states that deficient transmission planning threatens the justness and reasonableness of transmission rates, and therefore the Commission has legal authority and jurisdiction to order changes to transmission planning to remedy that deficiency.¹⁴⁴ Harvard ELI further asserts that the Commission must remedy undue discrimination due to incumbent transmission owners' unduly discriminatory influence in regional transmission planning.¹⁴⁵ Massachusetts Attorney General also

¹²⁷ PacifiCorp and NV Energy Initial Comments at 10–11.

¹²⁸ National Grid Initial Comments at 6–7 (citing the then-preliminary findings from the ISO-NE 2050 Transmission Study).

¹²⁹ Indicated PJM TOs Initial Comments at 1.

¹³⁰ Maryland Energy Administration Initial Comments at 1 (citing Maryland Energy Administration ANOPR Initial Comments at 2).

¹³¹ AEE Reply Comments at 3–4.

¹³² See, e.g., ACEG Initial Comments at 11; Clean Energy Associations Initial Comments at 7–10; Grand Rapids NAACP Initial Comments at 17; Massachusetts Attorney General Initial Comments at 3–4; Pine Gate Initial Comments at 10–14; PIOs Initial Comments at 8.

¹³³ 762 F.3d at 57. See also ACEG Initial Comments at 13–14; Harvard ELI Initial Comments at 1–2; SEIA Initial Comments at 3.

¹³⁴ PIOs Initial Comments at 8.

¹³⁵ Southeast PIOs Reply Comments at 4 (citing Duke Initial Comments at 6–9; SERTP Sponsors Initial Comments at 31–36; Southern Initial Comments at 36–40).

¹³⁶ *Id.* at 5–6 (citing NOPR, 179 FERC ¶ 61,028 at PP 45, 47, 49, 53).

¹³⁷ *Id.* at 6–7 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 65).

¹³⁸ *Id.* at 6–7 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 65–66).

¹³⁹ *Id.* at 7 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67).

¹⁴⁰ ACEG Reply Comments at 7–8 (citing Alabama Commission Initial Comments at 2–3; Duke Initial Comments at 6–9; Idaho Power Initial Comments at 2–3; NRECA Initial Comments at 11; North Carolina Commission and Staff Initial Comments at 14; Pacific Northwest Utilities Initial Comments at 9–10; Utah Commission Initial Comments at 9–12).

¹⁴¹ *Id.* at 17.

¹⁴² Colorado Consumer Advocate Initial Comments at 21–23; Joint Consumer Advocates Initial Comments at 18–20.

¹⁴³ New Jersey Commission Initial Comments at 3–4.

¹⁴⁴ Harvard ELI Initial Comments at 1–2 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41; Order No.1000–A, 139 FERC ¶ 61,132 at PP 56–75).

¹⁴⁵ *Id.* at 3.

argues that the Commission's proposed reforms are necessary to fulfill the Commission's statutory obligation to ensure that transmission rates are just and reasonable.¹⁴⁶

71. Some commenters argue that there is insufficient evidence for the Commission to find that existing jurisdictional rates are unjust, unreasonable, and unduly discriminatory or preferential.¹⁴⁷ For example, while Idaho Commission recognizes that there are deficiencies in existing transmission planning and cost allocation processes, Idaho Commission disagrees with the NOPR's claim that their failure to identify and plan for transmission needs driven by changes in the resource mix and demand is resulting in unjust, unreasonable, and unduly discriminatory or preferential Commission-jurisdictional rates.¹⁴⁸ Mississippi Commission also disagrees that the lack of long-term regional transmission planning will result in unjust, unreasonable, and unduly discriminatory or preferential rates.¹⁴⁹ ELCON questions a finding of unjust, unreasonable, and unduly discriminatory or preferential rates, and it states that the NOPR's focus on Long-Term Regional Transmission Planning solely to address changes in resource mix and demand, if adopted, could fail to produce better outcomes for customers and may exceed the Commission's authority under the FPA.¹⁵⁰

72. Louisiana Commission states that the Commission's finding that, absent reforms, transmission rates universally are not just and reasonable and are discriminatory is not based on individual analysis of each RTO or region, is not supported, and should be retracted.¹⁵¹ Mississippi Commission also states that the Commission should, instead, initiate region-specific investigations pursuant to FPA section 206.¹⁵² Southern argues that the Commission has failed to satisfy the first prong of its FPA section 206 burden of proof, noting that the NOPR's preliminary conclusion, that existing

regional transmission planning processes are not sufficient to address changes in the resource mix and demand, cannot reasonably be made of Southern or SERTP.¹⁵³

73. Similarly, Industrial Customers argue that the Commission has not satisfied the first prong of FPA section 206, which requires the Commission to find, and provide substantial evidence supporting its finding, that existing rates are unjust, unreasonable, and unduly discriminatory or preferential.¹⁵⁴ Industrial Customers claim that demand growth should be the primary factor in identifying transmission needs, and that demand is growing more slowly than in previous periods. Industrial Customers add that, in contrast, investment in transmission is rising relative to demand, which is the opposite of the circumstances that prevailed in 2007 when the Commission issued Order No. 890.¹⁵⁵ According to Industrial Customers, changes in demand are not significant enough in historical terms to warrant major changes in transmission planning. Moreover, Industrial Customers state that changes in demand are unpredictable because technological changes are inherently difficult to forecast and the risks to consumers of making mistakes are too high. Industrial Customers argue that, if anything, the rapid growth of renewables indicates that current processes are already facilitating changes in the resource mix.¹⁵⁶ Similarly, NRG argues that long-term forecasts of important factors are often wrong, which has real-world impacts on customers.¹⁵⁷

74. Further, Industrial Customers contend that the NOPR does not clearly define the term "changes in the resource mix and demand," despite using such changes as the justification for the proposals. Industrial Customers argue that transmission should only be planned in order to maintain reliability and should not be based on the demand for certain fuel sources or the fuel type of the generation fleet.¹⁵⁸ Industrial Customers argue that current transmission planning is based on known and measurable factors, and that any attempt to plan for potential future

changes in the resource mix without determining precisely what these changes will be would result in the overbuilding of the system for generation that may not be built.

Industrial Customers argue that this outcome would be unjust and unreasonable and would force transmission customers to pay for generation that is non-existent.¹⁵⁹

75. Other commenters agree that the Commission lacks a specific record to support the need for reform.¹⁶⁰ For example, former Kansas Commission Chair Keen avers that there is no analytical or evidentiary basis in the NOPR for a complete and thorough overhaul or revision of transmission planning processes.¹⁶¹

76. Duke asserts that the NOPR does not provide robust and specific support as to how and why current regional transmission planning processes are failing to plan for transmission needs driven by changes in the resource mix and demand, leading to inefficient investment.¹⁶² Duke asserts that the NOPR does not support the presumption that the absence of significant regional transmission investment is evidence of inefficient transmission planning.¹⁶³ Duke also asserts that, to ensure legal durability, the Commission should identify evidence that justifies a nationwide finding that current transmission planning processes are failing to plan for transmission needs driven by changes in the resource mix and demand, leading to inefficient investment and unjust, unreasonable, and unduly discriminatory or preferential rates.¹⁶⁴

77. Undersigned States argue that the Commission does not have evidence in the record that current rates are unjust, unreasonable, or unduly discriminatory or preferential, which FPA section 206 requires.¹⁶⁵ Undersigned States argue

¹⁴⁶ Massachusetts Attorney General Initial Comments at 3–6.

¹⁴⁷ See, e.g., ELCON Initial Comments at 7; Idaho Commission Initial Comments at 2; Mississippi Commission Initial Comments at 2, 9; NRECA Initial Comments at 14–16; Undersigned States Reply Comments at 6–7.

¹⁴⁸ Idaho Commission Initial Comments at 2 (citing NOPR, 179 FERC ¶ 61,028 at P 34).

¹⁴⁹ Mississippi Commission Initial Comments at 2.

¹⁵⁰ ELCON Initial Comments at 7.

¹⁵¹ Louisiana Commission Reply Comments at 5–6.

¹⁵² Mississippi Commission Reply Comments at 7–9.

¹⁵³ Southern Initial Comments at 40; Southern Reply Comments at 1–3.

¹⁵⁴ Industrial Customers Initial Comments at 6–7.

¹⁵⁵ *Id.* at 8–10.

¹⁵⁶ *Id.* at 10–11.

¹⁵⁷ NRG Initial Comments at 10–12 (noting, for example, that "[p]redictions for the future price of natural gas and thus the economics of gas generation in long-term forecasts have been notoriously inaccurate." (citing Lawrence Berkeley National Laboratory, *Comparison of AEO 2008 Natural Gas Price Forecast to NYMEX Futures Prices* (Jan. 2008)).

¹⁵⁸ Industrial Customers Initial Comments at 7–8.

¹⁵⁹ *Id.* at 15.

¹⁶⁰ See, e.g., Alabama Commission Initial Comments at 4–5; Duke Initial Comments 6–9; Idaho Commission Initial Comments at 2; Industrial Customers Initial Comments at 1, 6–11, 15; Kansas Commission Chair Keen Initial Comments at 1–2; Nebraska Commission Initial Comments at 1–2; NRECA Initial Comments at 14–16; NRG Initial Comments at 3; Ohio Commission Federal Advocate Initial Comments at 5–6; Potomac Economics Initial Comments at 3–4; Southern Initial Comments at 40.

¹⁶¹ Kansas Commission Chair Keen Initial Comments at 2.

¹⁶² Duke Initial Comments at 6–7.

¹⁶³ *Id.* at 7–8.

¹⁶⁴ *Id.* at 9 (citing *Emera Me. v. FERC*, 854 F.3d 9, 24 (D.C. Cir. 2017)).

¹⁶⁵ Undersigned States Reply Comments at 6–7. The Undersigned States that submitted reply comments include the States of Texas, Utah, Alabama, Alaska, Arkansas, Florida, Georgia, Kansas, Kentucky, Louisiana, Mississippi, Montana,

that, contrary to the preliminary findings in the NOPR, the Southeast has developed significant and sufficient transmission infrastructure and renewable energy from 2015–2020. Undersigned States further argue that the Commission is supposed to enhance reliability, and that, because renewables are intermittent and inherently less reliable, forcing ratepayers to subsidize their use through financing the construction of additional transmission infrastructure is not consistent with the Commission's mission. Undersigned States also argue that the Commission has not justified replacing existing transmission planning processes with a new approach, so the NOPR is arbitrary and capricious.¹⁶⁶ Further, Undersigned States argue that the Commission has not offered a detailed justification for countering prior precedent in Order No. 1000 that “the regional transmission planning process is not the vehicle by which integrated resource planning is conducted.”¹⁶⁷

78. Some commenters assert that the intention of the NOPR is to improperly favor certain energy resources.¹⁶⁸ Consumer Organizations argue that solutions that allow for an equitable transition and make space for advancing technology and smaller energy systems are preferable to a rushed plan that favors certain resources, such as wind, solar, and battery storage, that have already proven to be inadequate.¹⁶⁹ ELCON adds that Congress did not give the Commission express authority to balance the FPA's just and reasonable rates requirement with the policy goal of connecting renewable resources to the transmission system.¹⁷⁰ SERTP Sponsors argue that Congress has not clearly provided the Commission with jurisdiction to presuppose generation decisions and thereby effect particular, substantive transmission outcomes; rather, SERTP Sponsors continue, Congress has expressly and unequivocally reserved generation authority to the states.¹⁷¹ Louisiana

Nebraska, Ohio, Oklahoma, South Carolina, and West Virginia. *Id.* at 1. The Undersigned States that submitted initial comments include the States of Utah, Alaska, Georgia, Idaho, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Montana, Nebraska, North Dakota, Ohio, Oklahoma, South Carolina, Texas, West Virginia, and Wyoming. Undersigned States Initial Comments at 5–6.

¹⁶⁶ Undersigned States Reply Comments at 6–8.

¹⁶⁷ *Id.* at 8 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 154).

¹⁶⁸ See, e.g., Consumers Organizations Initial Comments at 1–3; ELCON Initial Comments at 9–10.

¹⁶⁹ Consumers Organizations Initial Comments at 1–3.

¹⁷⁰ ELCON Initial Comments at 9–10 (citing 16 U.S.C. 824q(b)(4)).

¹⁷¹ SERTP Sponsors Initial Comments at 18.

Commission argues that the FPA does not confer on the Commission authority to engage in wide-scale public policymaking by enacting sweeping energy policy changes with far-reaching, nationwide effects.¹⁷²

79. Ohio Commission Federal Advocate states that the NOPR may be intended “to establish policies designed to encourage the massive transmission build-out that will doubtless be required to transition to an aspirational renewable future” and “to achieve narrow environmental policy objectives, not to address legitimate requirements under the Federal Power Act like ensuring just and reasonable rates or reliability.”¹⁷³ Former Kansas Commission Chair Keen claims that the NOPR encourages an extensive and expensive transmission build-out without considering the impact on state-jurisdictional generation mixes. He also claims that some of the NOPR proposals impose an accelerated pace for the transition from dispatchable to renewable resources, which could hasten the premature retirement of dispatchable generation and compromise regional and state power reliability. He also expresses concern that the NOPR proposals would force ratepayers in some states to pay for neighboring states' transmission projects to advance public policy goals that they do not share.¹⁷⁴

80. Some commenters challenge aspects of the need for reform. For example, Nebraska Commission believes that the established structures in RTO/ISO regions are generally working and that many aspects of the NOPR are thus unnecessary there.¹⁷⁵ Potomac Economics disagrees with some of the Commission's arguments for requiring Long-Term Regional Transmission Planning, contending that the Commission's proposals are based on anticipated future generation and other speculative factors and seem to be incorrectly premised on a presumption that congestion should not exist or may limit investment in economic generation. Potomac Economics states that investment should occur only to the extent that the savings of reducing congestion are larger than the investment costs. According to Potomac Economics, congestion that is caused by generators' siting decisions should be

¹⁷² Louisiana Commission Initial Comments at 6 (citing *West Virginia v. EPA*, 597 U.S. 697 (2022)).

¹⁷³ Ohio Commission Federal Advocate Initial Comments at 4–5 (citing NOPR, 179 FERC ¶ 61,028, Danly, Comm'r, dissenting, at PP 2–3).

¹⁷⁴ Kansas Commission Chair Keen Initial Comments at 3.

¹⁷⁵ Nebraska Commission Initial Comments at 1–2.

borne by the generation developers, as it will incent them to propose the lowest-cost projects taking transmission costs into account. Potomac Economics argues that, if transmission is expanded preemptively to facilitate generation investment in a particular location, such costs are equivalent to subsidies for the developer.¹⁷⁶

81. Mississippi Commission disagrees that too much expansion of high-voltage transmission has occurred through the generator interconnection process instead of through regional transmission planning.¹⁷⁷ Similarly, North Carolina Commission and Staff disagree with the Commission's conclusion that the growth in interconnection-related network upgrades demonstrates a failure of regional transmission planning as it relates to North Carolina.¹⁷⁸ Southern adds that, contrary to statements in the NOPR, it is not significantly expanding its transmission system through the generator interconnection process.¹⁷⁹

82. Alabama Commission asserts that Alabama has a resource planning process that accounts for needed transmission buildout to maintain reliable service, and thus, Alabama Power plans its transmission system proactively both to maintain deliveries from existing resources and to accommodate Alabama Commission-certified generation additions. Alabama Commission claims that the SERTP process builds on the integrated resource planning efforts of its sponsor states, ensuring that there are no regional transmission solutions that are more efficient or cost-effective than solutions identified through the underlying state-jurisdictional processes.¹⁸⁰

83. Duke argues that, for certain transmission providers, the local transmission planning process may more effectively meet transmission needs, especially when combined with state-regulated integrated resource planning and a bottom-up regional transmission planning process. Duke contends that a regional transmission facility may not fully address local transmission needs such that a local transmission facility would still be needed, and thus, the regional transmission facility is not necessarily more efficient or cost-effective than the local transmission facility.¹⁸¹

¹⁷⁶ Potomac Economics Initial Comments at 3–4.

¹⁷⁷ Mississippi Commission Initial Comments at 9.

¹⁷⁸ North Carolina Commission and Staff Initial Comments at 5.

¹⁷⁹ Southern Initial Comments at 38–40.

¹⁸⁰ Alabama Commission Initial Comments at 4.

¹⁸¹ Duke Initial Comments at 7–9.

84. NRECA states that certain of its members in RTOs/ISOs believe that regional transmission planning is working well to meet long-term needs (e.g., those in MISO) and that the NOPR proposals would burden transmission providers' limited resources. NRECA states that other NRECA members in RTOs/ISOs believe that existing RTO/ISO transmission planning processes contain discrete deficiencies that the NOPR proposals will not remedy. According to NRECA, these electric cooperatives believe that some incumbent investor-owned transmission owners develop local transmission projects without transparency concerning need or costs, leading to disparities in transmission rates across RTO/ISO transmission zones, and that incumbent transmission owners control the transmission planning process such that no regional transmission planning occurs. NRECA states that, in these cooperatives' view, the criteria to determine the eligibility of a regional transmission project is the barrier, and that requiring Long-Term Regional Transmission Planning, by itself, will not solve the problem.¹⁸²

C. Commission Determination

85. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential. We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that the absence of sufficiently long-term, forward-looking, and comprehensive transmission planning requirements is causing transmission providers to fail to adequately anticipate and plan for future system conditions. It causes transmission providers to fail to appropriately evaluate the benefits of transmission infrastructure, and results in piecemeal transmission expansion to address relatively near-term transmission needs. We find that this status quo causes transmission providers to undertake relatively inefficient investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. This dynamic results in, among other things, transmission customers paying more than necessary or appropriate to meet their transmission needs and forgoing benefits that outweigh their costs, which results in less efficient or cost-effective transmission investments. As explained

below, we find that these deficiencies render Commission-jurisdictional regional transmission planning and cost allocation processes unjust, unreasonable, and unduly discriminatory or preferential.

86. The Commission has authority under FPA section 206 to issue this final order. Specifically, FPA section 206 "instructs the Commission to remedy 'any . . . practice' that 'affect[s]' a rate for interstate electricity service 'demanded' or 'charged' by 'any public utility' if such practice is 'unjust, unreasonable, unduly discriminatory or preferential.'" ¹⁸³ As the D.C. Circuit has recognized, regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission's exclusive jurisdiction.¹⁸⁴ As the Court explained in *South Carolina Public Service Authority v. FERC*, transmission providers use those processes to "determine which transmission facilities will more efficiently or cost-effectively meet" transmission needs, the development of which directly impacts the rates, terms, and conditions of Commission-jurisdictional service.¹⁸⁵ In particular, because these processes identify, evaluate, and select the regional transmission facilities whose costs will be recovered through transmission rates, we find that they directly affect those rates.¹⁸⁶ In addition, as discussed below, such transmission facilities contribute to the development of a more robust transmission system, supporting continuity of service in the face of growing reliability challenges and providing wholesale electric customers greater access to lower-cost generation supplied by a wider range of resources. Accordingly, regional transmission

planning and cost allocation processes, as well as "the rules and practices that determine how those [processes] operate,"¹⁸⁷ have a direct effect on the rates that customers pay for *both* the transmission and sale of electric energy in interstate commerce.¹⁸⁸ The Commission may act pursuant to FPA section 206 if the Commission first establishes, through substantial evidence,¹⁸⁹ that the existing practices are unjust, unreasonable, or unduly discriminatory or preferential and, second, establishes that the replacement practices are just and reasonable.¹⁹⁰

87. With regard to the first showing under FPA section 206, we find that, while Order No. 890 requires transmission providers to satisfy certain principles in their local transmission planning processes and Order No. 1000 requires transmission providers to participate in regional transmission planning and cost allocation processes that satisfy the requirements set forth therein, these existing transmission planning and cost allocation requirements do not result in regional transmission planning that is conducted on a sufficiently long-term, forward-looking, and comprehensive basis to plan for Long-Term Transmission Needs. As a result, we find that transmission providers are often not identifying, evaluating, or selecting more efficient or cost-effective regional transmission solutions to meet Long-Term Transmission Needs. This gap in existing regional transmission planning processes results in piecemeal, inefficient, and less cost-effective transmission planning that imposes real costs on customers, who pay Commission-jurisdictional transmission rates for less efficient or cost-effective transmission facilities and do not realize the benefits that would result from long-term, forward-looking, and more comprehensive regional transmission planning and cost allocation processes that identify, evaluate, and select more efficient or cost-effective transmission

¹⁸³ *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55 (quoting 16 U.S.C. 824e(a)).

¹⁸⁴ *Id.* at 55–59, 84 (affirming the Commission's authority to regulate transmission planning and cost allocation as practices affecting rates); *see also* Order No. 1000–A, 139 FERC ¶ 61,132 at P 577 (holding that "requirements regarding transmission planning and cost allocation . . . are practices affecting rates.").

¹⁸⁵ *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 56 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 112, 116); *see also* *Emera Me. v. FERC*, 854 F.3d at 674.

¹⁸⁶ That is true even if regional transmission planning and cost allocation processes do not result in the development, siting, and construction of every regional transmission facility that transmission providers select to more efficiently or cost-effectively meet transmission needs. *See, e.g., Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 485 (D.C. Cir. 2009) (holding that "even if all [that] the [I]n[stalled] C[apacity] R[equirement] did was help to find the right [capacity] price," rather than result in the construction or procurement of any new capacity, "it would still amount to a 'practice . . . affecting' rates." (citing 16 U.S.C. 824e(a) (omission in original))).

¹⁸⁷ *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 279 (2016) (*EPSA*).

¹⁸⁸ 16 U.S.C. 824e(a).

¹⁸⁹ *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 54 ("The Commission's factual findings are conclusive if supported by substantial evidence."). Courts have held that substantial evidence in this context does not necessarily require the Commission to provide empirical evidence for every proposition. Rather, FPA section 206 empowers the Commission to address a mere threat of unjust and unreasonable rates. *See S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 64–65, 85.

¹⁹⁰ 16 U.S.C. 824e(a); *see also* *EPSA*, 577 U.S. at 277 (affirming the Commission "has the authority—and indeed, the duty—to ensure that rules or practices 'affecting' wholesale rates are just and reasonable").

¹⁸² NRECA Initial Comments at 14–16.

solutions to Long-Term Transmission Needs.

88. We find that these deficiencies in the Commission's existing transmission planning and cost allocation requirements render those requirements unjust, unreasonable, and unduly discriminatory or preferential in violation of FPA section 206.

89. We also find that the Commission's existing transmission planning and cost allocation requirements are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates. Given these findings, we are now requiring, pursuant to FPA section 206, that transmission providers engage in and conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes to identify and plan for Long-Term Transmission Needs. We find that these reforms will facilitate a process by which transmission providers can better identify, evaluate, and select more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs, which will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

1. The Transmission Investment Landscape Today

90. As the Commission explained in the NOPR, a robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity.¹⁹¹ Due to continuing changes in the industry, ongoing investment in transmission facilities is necessary to ensure the transmission system continues to serve load in a reliable,¹⁹² affordable, and economically efficient fashion. Such investments support enhanced reliability, as larger, more integrated transmission systems result in a diversity of supply and demand conditions and a certain degree of redundancy that allows the system to

better withstand failures during extreme events.¹⁹³ Proactive, forward-looking transmission planning that considers both evolving reliability needs and other drivers of transmission needs more comprehensively can enable transmission providers to identify potential reliability problems and economic constraints, as well as to evaluate potential transmission solutions, well in advance of these issues affecting the transmission system,¹⁹⁴ which can facilitate the selection of more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs.

91. In addition, transmission infrastructure can unlock the forces of competition, changing who can sell to whom, eliminating barriers to entry, and mitigating market power.¹⁹⁵ Increased competition, in turn, can provide a host of benefits for customers, including cost-savings from greater access to low-cost power and a wider range of resources.¹⁹⁶ Transmission

¹⁹³ ACORE ANOPR Initial Comments Ex. 4, Grid Strategies July 2021 Extreme Weather Report; Mark Chupka & Pearl Donohoo-Vallett, *Recognizing the Role of Transmission in Electric System Resilience* (May 2018), <https://wiresgroup.com/wp-content/uploads/2020/06/2018-05-09-Brattle-Group-Recognizing-the-Role-of-Transmission-in-Electric-System-Resilience-.pdf>; NERC ANOPR Initial Comments at 17–18; US DOE ANOPR Initial Comments at 18.

¹⁹⁴ MISO's Multi-Value Project (MVP) regional transmission planning process, for example, eliminated the need for approximately \$300 million in reliability transmission facilities, resolving reliability violations and mitigating system instability conditions, through a forward-looking approach. Midcontinent Independent System Operator, *MTEP17 MVP Triennial Review: A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio*, at 11, 33 (Sept. 2017) (MTEP2017 Review).

¹⁹⁵ Policy Integrity ANOPR Initial Comments at 13 n.40 (“A new transmission project can enhance competition by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load.” (citing Mohamed Awad et al., *The California ISO Transmission Economic Assessment Methodology (TEAM): Principles and Applications to Path 26*, at 3 (2006)); PIOs ANOPR Initial Comments Ex. A, Johannes Pfeifenberger et al., The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, at 48–49 (Oct. 2021) (Brattle-Grid Strategies Oct. 2021 Report), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-Grid-Strategies-Transmission-Planning-Report_v2.pdf (“Expansion of the transmission network typically increases the number of independent wholesale electricity suppliers that are able to compete to supply electricity at locations in the transmission network served by the upgrade” (quoting F.A. Wolak, World Bank, *Managing Unilateral Market Power in Electricity*, Policy Research Working Paper No. 3691, at 8 (2005))).

¹⁹⁶ See, e.g., PJM Interconnection, L.L.C., *PJM Value Proposition*, at 1–2 (2019), <https://www.pjm.com/about-pjm/-/media/about-pjm/pjm-value-proposition.ashx> (PJM's planning of resource

infrastructure can also serve as a form of insurance against future uncertainties because a more robust, integrated transmission system has the potential to provide consumers with the benefits of competition and enhanced reliability even if supply and demand fundamentals change over time.¹⁹⁷

92. With that overview, we again begin with the key facts on the ground.¹⁹⁸ Since the issuance of Order No. 1000, transmission spending has continued to increase nationwide. A study by US DOE found that “annual investment [in transmission] first exceeded \$5 billion per year in 2006 . . . and has increased consistently since that time. Annual investment [] doubled to more than \$10 billion per year by 2010 and then [] doubled again by 2016. Annual investment has been between \$18 billion and \$22 billion annually since 2014.”¹⁹⁹ A separate study, noted by the Commission in the NOPR, estimated that transmission developers in the United States invested \$20 to \$25 billion annually in transmission facilities from 2013 to 2020.²⁰⁰ Unsurprisingly, in regions that saw a significant increase in transmission expenditures, transmission costs have also become an increasing

adequacy over a large region is estimated to result in savings of \$1.2–1.8 billion.; Midcontinent Independent System Operator, *MISO Value Proposition* (2020), https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/ (MISO estimated \$517–572 million in savings from more efficient use of existing assets and \$2.5–3.2 billion from reduced need for additional assets.); SPP Transmission Planning, Southwest Power Pool, *SPP's Value of Transmission: 2021 Report and Update* (Mar. 31, 2022) (SPP estimated \$382.7 million in adjusted product costs savings in 2020 due to transmission investment.); see also ACEG Initial Comments at 3–4 (“The benefits generated by MISO's MVPs and SPP's Priority Projects exceeded the costs by 2.2 to 3.5 times and means that every dollar spent on transmission will enable access to generation that is \$3 to \$4 cheaper than would otherwise be available.”).

¹⁹⁷ US DOE, *National Electric Transmission Congestion Study*, at 11 (Sept. 2015), https://www.energy.gov/sites/prod/files/2015/09/f26/2015%20National%20Electric%20Transmission%20Congestion%20Study_0.pdf (stating transmission expansion can strengthen and increase the flexibility of the overall network and “create real options to use the transmission system in ways that were not originally envisioned”); Vikram S. Budhbraja et al., *Improving Electricity Resource Planning Processes by Considering the Strategic Benefits of Transmission*, 22 ELEC. J. 54 (Mar. 2009) (high voltage transmission affords “mitigation of risks as a form of insurance against extreme events”).

¹⁹⁸ NOPR, 179 FERC ¶ 61,028 at P 36.

¹⁹⁹ California Commission Reply Comments at 9 n.27 (quoting US DOE, *National Electric Transmission Congestion Study*, at 9–10 (Sept. 2020), <https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf>).

²⁰⁰ NOPR, 179 FERC ¶ 61,028 at P 39 (citing Brattle-Grid Strategies Oct. 2021 Report at 2); Brattle Apr. 2019 Competition Report at 2–3 & fig.1.

¹⁹¹ NOPR, 179 FERC ¶ 61,028 at P 28 (citing 16 U.S.C. 824, 824d, 824e); see also US DOE ANOPR Initial Comments at 2 (stating that “strengthening and expanding existing transmission infrastructure, particularly the development of regional and inter-regional transmission projects, is key to continued access to reliable, resilient, lower-cost, and clean electricity for all”).

¹⁹² See, e.g., MISO ANOPR Initial Comments at 40; Testimony of James B. Robb Before the U.S. Senate Energy and Natural Resources Committee, *Reliability, Resiliency, and Affordability of Electric Service in the United States Amid the Changing Energy Mix and Extreme Weather Events*, at 8–9 (Mar. 11, 2021), <https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11> (testifying that more transmission infrastructure is required to ensure the reliability and resilience of the bulk power system in light of changing conditions).

share of customers' overall electricity bills, underscoring the importance of ensuring that transmission investments are efficient and cost-effective.²⁰¹

93. Furthermore, the record demonstrates that transmission investment is likely to substantially increase in coming years. A number of studies project significant and sustained transmission spending through at least 2050. For example, one projection cited by the US DOJ and FTC states that "high voltage transmission capacity must expand by 60 percent by 2030 at a capital cost of \$330 billion, and must triple by 2050 at a capital cost of \$2.2 trillion."²⁰² TAPS cites a separate study projecting \$750 billion of new transmission investment between 2023 and 2050.²⁰³ SoCal Edison "estimates that grid investments of up to \$75 billion, including transmission upgrades, will be required from 2030 to 2045 in California alone to integrate bulk renewable generation and storage and serve load growth associated with electrification."²⁰⁴ And ISO-NE's

recently-completed 2050 Transmission Study estimates that transmission investment in New England will range from \$16 billion to \$26 billion between 2024 and 2050, depending on the amount of load growth realized in the region.²⁰⁵

94. The growing need for new transmission infrastructure, particularly over a longer time horizon, is being driven by a number of factors. First, longer-term reliability needs are changing. The NOPR explained that transmission system operators are increasing their reliance on regional transmission facilities to ensure operational stability, particularly because of the growing frequency of extreme weather events and increasing share of variable resources entering the resource mix.²⁰⁶ The comments submitted in response to the NOPR support that preliminary finding. The record shows that changing reliability needs are driving a significant shift in demands placed on the transmission system,²⁰⁷ and that because extreme weather events are occurring with greater frequency, transmission is increasingly critical to ensuring system reliability.²⁰⁸ For example, Winter

Storm Uri demonstrated that transmission infrastructure can make critical contributions to system reliability during extreme weather events,²⁰⁹ as well as how transmission constraints can prevent operational generation resources from being able to serve load during tight supply conditions.²¹⁰ Consistent with experience from Winter Storm Uri, US DOE's Lawrence Berkeley National Laboratory provides further evidence of the significant value of transmission during unanticipated events, with research suggesting that 50% of the value created by alleviating transmission system congestion occurs during only 5% of the hours during which the transmission system is used.²¹¹ Thus, transmission investment is likely to be more critical, and produce more reliability benefits, for customers as extreme weather and other system contingencies become more frequent.²¹² For some communities who can be more susceptible to the impacts of extreme weather, like communities of color and

risks (tail risks) related to extreme weather" (internal quotations omitted); NYISO Initial Comments at 16 (expressing a desire to engage in actionable scenario planning to plan for future reliability challenges that may arise due to extreme weather, including the loss of all generation connected to a pipeline or other fuel sources, loss of an entire transmission line, and impacts from weather events like hurricanes or wildfires).

²⁰⁹ ACEG Initial Comments at 22 n.63 (During Winter Storm Uri, "[a]n additional 1 gigawatt (GW) of transmission ties between ERCOT and the Southeastern U.S. could have saved nearly \$1 billion and kept power flowing to hundreds of thousands of Texans." (citing Grid Strategies July 2021 Extreme Weather Report at 1–3, 12)); Grid Strategies July 2021 Extreme Weather Report at 7–8 ("The value of transmission for resilience can be seen in the drastically different outcomes of MISO and SPP relative to ERCOT during [Winter Storm Uri]. . . . In contrast to the 13,000 MW MISO was importing during the peak of [the] event, ERCOT was only able to import about 800 MW of power throughout the event."); NARUC Initial Comments at 67 n.192 (During Winter Storm Uri, SPP's "relationships and interconnections with neighboring systems were critical. Usually a net exporter of energy, SPP relied significantly on imported energy to serve load during the winter event, with net amounts exceeding 6,000 megawatts (MW) at times. This emphasizes the value these relationships and robust transmission interconnections provide during emergency events and the opportunity to further strengthen them." (quoting Southwest Power Pool, *A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations*, at 9 (July 2021), <https://spp.org/documents/65037/comprehensive%20review%20of%20spp%27s%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf> (brackets omitted))).

²¹⁰ See Advanced Energy Buyers Initial Comments at 3.

²¹¹ ACORE Initial Comments at 10–11 (citing LBNL Aug. 2022 Transmission Value Study at 33); US DOE Initial Comments at 5–6 & n.13.

²¹² ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33; see also Clean Energy Associations Initial Comments at 5.

²⁰¹ Resale Iowa Initial Comments at 3 ("[T]ransmission costs have comprised an increasing percentage of [] total wholesale electric costs [for Resale Iowa's members]. Currently, transmission and ancillary services constitute approximately 43% of such costs, as compared to 18.1% in 2009."); Industrial Customers Initial Comments at 5 (showing that transmission costs made up just 7% of the total PJM electricity bill in 2011 but 27% by 2020); Rob Gramlich and Jay Caspari, Americans for a Clean Energy Grid, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 26–28 (Jan. 2021), <https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG-Planning-for-the-Future1.pdf> (ACEG Jan. 2021 Planning Report) (stating that the current approach to transmission planning "results in higher total energy bills for customers than would result from more forward-looking, holistic transmission planning"); see also California Municipal Utilities Initial Comments at 10 (projecting that between 2022 and 2040, total high and low-voltage transmission access charges will nearly double and noting that "[g]one are the days when transmission was a *de minimis* portion of the overall bill and increases had little impact on the end consumer"); Public Systems Initial Comments at 5 (noting that "New England's Regional Network Service transmission rate has grown *nine-fold*, from \$15.60 per kW-year (in 2003) to \$140.98 per kW-year (in 2021)").

²⁰² US DOJ and FTC Initial Comments at 3 (citing Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Princeton Univ., 108 (Oct. 2021), <https://netzeroamerica.princeton.edu/the-report>).

²⁰³ TAPS Initial Comments at 46 & n.133 (citing Jürgen Weiss et al., The Brattle Group, *The Coming Electrification of the North American Economy*, at iii (2019), <https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf>).

²⁰⁴ SoCal Edison Initial Comments at 2 (citing Southern California Edison, *Pathway 2045: Update to the Clean Power and Electrification Pathway* (2019), https://download.newsroom.edison.com/create_memory_file/?f_id=5dc0be0b2cfac24b300fe4ca&content_verified=True) (emphasis added)).

²⁰⁵ ISO-NE, *2050 Transmission Study*, at 55–56 (Feb. 12, 2024), https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf.

²⁰⁶ NOPR, 179 FERC ¶ 61,028 at P 45.

²⁰⁷ ACEG Initial Comments at 5 (noting that weather-related power outages cost Americans \$25–70 billion annually (citing Grid Strategies July 2021 Extreme Weather Report at 1)); *id.* at 52 (explaining that "[c]hanges to the transmission planning processes that would allow for certain transmission upgrades identified in the interconnection process to be addressed and ultimately constructed through the transmission planning process will only serve to increase the resiliency and reliability of the transmission system."); ACEG Reply Comments at 5–6 ("[R]eliability requires long term transmission planning that incorporates known and knowable information about the future resource mix."); NERC Initial Comments at 6 ("Transmission will be the key to support the resource transformation enabling delivery of energy from areas that have surplus energy to areas which are deficient. The frequency of such occurrences are increasing as extreme weather conditions resulting from climate change impact the fuel sources for variable energy resources. Regional transmission planning can ensure that sufficient amounts of transmission capacity will be needed to address these more frequent extreme weather conditions.").

²⁰⁸ See DC and Maryland Offices of People's Counsel Reply Comments at 2 (noting that new transmission development has benefits including enhanced reliability and resilience that will serve as a necessary bulwark against disruptions caused by extreme weather); Indicated PJM TOs Initial Comments at 1 (explaining that maintaining a "reliable and resilient" transmission system requires holistic planning); NESCOE Initial Comments at 32–33 ("ISO-NE explains that energy-security risks in New England are well documented, highlighting the importance of conducting comprehensive energy security assessments covering a wide range of operating conditions, including low-probability, high-impact reliability

low-income communities, transmission investment has the potential to be even more critical.²¹³ Conversely, failure to adequately plan the transmission system to meet such changing reliability needs will forgo many of those potential benefits, jeopardize system reliability, and force customers to pay for transmission facilities that may not efficiently or cost-effectively address urgent reliability needs.

95. Second, demand is changing. After many years of flat or minimal load growth in regions across the country, demand, on both a national and a regional basis, is projected to significantly increase in the coming decades, and it will require an increasingly robust transmission system to reliably serve this load growth. As stated in the NOPR, changes in electric demand and associated load profiles are occurring as load-serving entities work to meet increasing needs due to electrification trends, as well as new large loads associated with evolving industrial and commercial needs, such as growth in data centers.²¹⁴ The comments submitted in this record demonstrate that, in regions across the country, customers are electrifying everything from household appliances to vehicles.²¹⁵ Comments also

substantiate the fact that, in many regions, large loads associated with new and emerging industrial needs, like data centers, are driving rapid load growth.²¹⁶ Estimates quantifying the magnitude of this shift show that it is significant, with nationwide demand for electricity projected to increase by 5% to 15% (200 to 600 TWh) by 2030.²¹⁷ That trend is projected not just to continue but to accelerate, with nationwide demand for electricity projected to increase by 25% to 85% (1,100 to 3,700 TWh) by 2050.²¹⁸

Results, at 190–94 (Nov. 2023) (providing sensitivity that included 15% and 10% increases in peak load and average hourly loads, respectively, driven by heating and vehicle electrification); U.S. Energy Info. Admin. (EIA), *Incentives and Lower Costs Drive Electric Vehicle Adoption in Our Annual Energy Outlook*, (May 15, 2023) (noting that, per 2023 Annual Energy Outlook Projections, electric vehicles will account for between 13% and 29% of new light-duty vehicle sales in the United States, and between 11% and 26% of then on-road light duty vehicle stocks, by 2050).

²¹⁶ See, e.g., Transmission Dependent Utilities Initial Comments at 4–5 (“For example, the PJM Interconnection, L.L.C. Transmission Expansion Advisory Committee recently posted that Dominion Energy Virginia will need over \$603 million in transmission upgrades through 2025—just three years from now—to accommodate significant data center load growth in Northern Virginia.” (citing PJM Transmission Advisory Committee, *Reliability Analysis Update*, at 3, 5 (Aug. 9, 2022))). These trends are continuing and even accelerating. See PJM Interconnection, L.L.C., *PJM Load Forecast Report*, at 1 (Jan. 2024), <https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx> (noting upward adjustments in 2024 load forecasts for certain zones to account for large, unanticipated load growth driven by data centers, a chip processing plant, and port electrification, among other factors); *id.* at 78 (projecting increase from 2,333 GWh in 2024 to 130,489 GWh in 2039 due to plug-in electric vehicles); *id.* at 30 (showing 1.0% higher load growth projection for 2024, 6% higher load growth projection for 2029, and 10.4% higher load growth projection for 2034, as compared to 2023 Load Forecast Report).

²¹⁷ National Grid Initial Comments at 8 (citing Jürgen Weiss et al., *The Brattle Group, The Coming Electrification of the North American Economy* (Mar. 2019), <https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Comeing-Electrification-of-the-NA-Economy.pdf>).

²¹⁸ *Id.*; see also John D. Wilson and Zach Zimmerman, *Grid Strategies, The Era of Flat Power Demand is Over*, at 3 (Dec. 2023), <https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf> (“Over [2023], grid planners nearly doubled the 5-year load growth forecast. The nationwide forecast of electricity demand shot up from 2.6% to 4.7% growth over the next five years, as reflected in 2023 FERC [Form 714] filings. Grid planners forecast peak demand growth of 38 gigawatts (GW) through 2028.”); N. Amer. Elec. Reliability Corp., *2023 Long-Term Reliability Assessment*, at 33 (Dec. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf (“Electricity peak demand and energy growth forecasts over the 10-year assessment period are higher than at any point in the past decade. The aggregated assessment area summer peak demand forecast is expected to rise by 79 GW, and aggregated winter peak demand forecasts are increasing by nearly 91 GW. Furthermore, the

Industrial customers in many regions are driving much of this increase; industry executives have reported that electrification initiatives, through which many of the Nation’s largest companies plan to electrify their manufacturing processes, transportation, and heating operations, are well underway or soon to begin.²¹⁹ Importantly, the record shows that these increases in aggregate demand for electricity will have significant consequences for the transmission system. To serve more load, the capacity of the already-oversubscribed transmission system will need to increase.²²⁰ Moreover, load growth driven primarily by electrification can create a load profile that has a higher load factor and that is thus more challenging to serve.²²¹

96. Third, supply is changing. As the NOPR explained, Federal, state, and local policies are incentivizing various forms of generation resources and other technologies,²²² resulting in changes to the Nation’s resource mix. The comments in this record show that these policies are widespread and now span

growth rates of forecasted peak demand and energy have risen sharply since the 2022 [Long-Term Reliability Assessment], reversing a decades-long trend of falling or flat growth rates.”).

²¹⁹ Renewable Northwest Initial Comments at 20 (“A recent study done by Deloitte showed that 70 percent of executives in industrial manufacturing industries have plans for the electrification of industrial processes, and 50 percent of the executives who responded have goals to electrify vehicle fleets and space and water heating within their companies by 2030.” (citing Stanley Porter et al., *Deloitte, Electrification in Industrials* (Aug. 2020), <https://www2.deloitte.com/us/en/insights/industry/power-and-utilities/electrification-in-industrials.html>)).

²²⁰ See, e.g., National Grid Initial Comments at 6 (discussing preliminary findings of the ISO–NE 2050 Transmission Study, which show “significant new transmission will be needed to reliably serve” increased future loads assumed in the study (citing ISO–NE, *2050 Transmission Study* (2023), https://www.iso-ne.com/static-assets/documents/2023/08/2050_study_ma_cetwg_2023_aug_final.pdf)); Northwest and Intermountain Initial Comments at 5 n.12 (“For example, Bonneville Power Administration (‘BPA’) owns about 75 percent of the transmission lines in the Pacific Northwest. In BPA’s 2022 Transmission Service Expansion Plan cluster study, customers submitted 153 separate transmission service requests totaling 11,831 MW of transmission capacity. BPA was able to offer service (without requiring detailed studies and transmission upgrades) to only 275 MWs of those service requests.” (citing BPA, *TSR Study and Expansion Process*, at 12 (Dec. 2021), <https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2021-22sep-overview.pdf>)).

²²¹ MISO Initial Comments at 54 (“In addition, a return to load growth driven primarily by the electrification of transportation, space heating and water heating is creating a load profile that has a higher load factor and is more challenging to serve.”). Load factor refers to “[t]he ratio of the average load to peak load during a specified time interval.” U.S. Energy Info. Admin. (EIA), *Glossary* (last visited Mar. 2024), <https://www.eia.gov/tools/glossary/index.php?id=L>.

²²² NOPR, 179 FERC ¶ 61,028 at P 45.

²¹³ See, e.g., WE ACT Initial Comments at 1–2 & n.3 (citing Jeff Turrentine, NRDC, *A Roadmap for Frontline Communities* (Dec. 2019)); see also Grand Rapids NAACP Initial Comments at 8 n.20 (“[P]ower outages uniquely burden low-income communities of color ‘given that they are unable to ‘bounce back’ as quickly from events that damage food and medicine supplies’” (citing Shalanda Baker et al., *The Energy Justice Workbook 20* (2019), <https://iejusa.org/wp-content/uploads/2019/12/The-Energy-Justice-Workbook-2019-web.pdf>)).

²¹⁴ NOPR, 179 FERC ¶ 61,028 at PP 45, 51. The continuation and, in some instances, acceleration of these trends identified in the ANOPR and NOPR counters certain commenters’ concerns that changes in demand are inherently unpredictable or that existing regional transmission planning processes are adequately identifying and addressing transmission needs. Compare *infra* notes 21515–2188 and accompanying discussion, with Potomac Economics Initial Comments at 3–4 (arguing that Long-Term Regional Transmission Planning that requires speculating about future uncertainty is not advisable), and Industrial Customers Initial Comments at 10–11 (arguing that changes in demand are unpredictable).

²¹⁵ AEE Initial Comments at 1, 14 (noting that, as of 2022, “[n]ine states have also taken steps directly to promote electrification of transportation and buildings. Individuals and governments are also adopting electric vehicles; for example, light-duty electric vehicle sales have increased from 10,092 vehicles in 2011 to 459,426 vehicles in 2021, over a 4400% increase.”); Renewable Northwest Initial Comments at 20 (explaining that heat pumps installed as part of building electrification could add large new weather-dependent loads, estimated at 20,000 to 40,000 MW of incremental peak capacity by 2050 across the Pacific Northwest); see also AMP Initial Comments at 4; ISO–NE, *Operational Impact of Extreme Weather Events: Final Report on the Probabilistic Energy Adequacy Tool (PEAT) Framework and 2027/2032 Study*

many regions of the country. States and cities in the Northeast,²²³ Mid-Atlantic,²²⁴ Midwest,²²⁵ West,²²⁶ and Southeast²²⁷ have adopted binding state laws requiring emissions reductions. Moreover, with the passage of the Inflation Reduction Act in 2022, Congress has enacted legislation that will further spur investment nationwide in renewable and non-emitting resources.²²⁸

²²³ National Grid Initial Comments at 6–7 (explaining how all six states in New England have renewable energy standards and how ISO-NE’s 2050 Transmission Study demonstrates the demands that meeting those standards will place on New England’s transmission system); *id.* at 7 (explaining how the Climate Leadership and Community Protection Act enacted in New York State requires 70% renewable generation by 2030, zero-emissions by 2040, and 85% economy-wide emissions reductions by 2050, and that transmission infrastructure will be critical in meeting those goals); NESCOE Initial Comments at 15 (“Achieving a decarbonized system is required by laws and mandates in Connecticut, Maine, Massachusetts, Rhode Island, and Vermont.”).

²²⁴ DC and MD Offices of People’s Counsel Initial Comments at 18 (noting that “both Maryland and the District have adopted ambitious jurisdiction-wide decarbonization policies applicable to the [electric distribution companies] regulated by their respective public service commissions.”).

²²⁵ Illinois Commission Initial Comments at 5 (explaining that “[i]n Illinois, the Climate and Equitable Jobs Act of 2021 . . . will affect the future resource mix and demand and lead to decarbonization and electrification. For example, [it] requires Illinois to completely transition to clean energy by 2050 and facilitates electrification through the promotion of electric vehicles.”).

²²⁶ Renewable Northern Initial Comments at 6 (explaining that, “[c]urrently, 80 percent of NorthernGrid’s load is subject to state clean energy laws, and by 2040 NorthernGrid will have 65 percent carbon-free energy.”); *id.* at 21 (explaining that Washington state’s “SB 5974 sets a goal of all vehicles sold in 2030 and beyond to be [electric vehicles], with that goal becoming a mandate in 2035[.]”).

²²⁷ SREA Initial Comments at 25 (noting that North Carolina has adopted Renewable Energy and Energy Efficiency Portfolio Standards and enacted the North Carolina Carbon Plan).

²²⁸ ACOE Initial Comments at 1–2 & n.2 (projecting that “annual additions increasing from 15 GW of wind and 10 GW of utility-scale solar PV in 2020 to an average of 39 GW/year of wind additions in 2025–2026 (~2x the 2020 pace) and 49 GW/year of solar (~5x the 2020 pace), with solar growth rates increasing thereafter.” (citing REPEAT Project, *Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022*, at 15 (2022), https://repeatproject.org/docs/REPEAT_IRA_Preliminary_Report_2022-08-12.pdf)); CARE Coalition Initial Comments at 17 (“Analysis suggests that the [Inflation Reduction Act] could more than triple clean energy production in the U.S. and lead to \$600 billion in capital investment in clean energy infrastructure.” (citing American Clean Power Ass’n, *It’s a Big Deal for Job Growth and for a Clean Energy Future* (2022), <https://cleanpower.org/blog/its-a-big-deal-for-job-growth-and-for-a-clean-energy-future/>)); Evergreen Action Initial Comments at 3–4 (discussing model showing that clean energy could comprise up to 81% of all U.S. generation as a result of increased incentives in the Inflation Reduction Act (citing John Larsen et al., Rhodium Group, *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act*

97. Customers are also driving changes in the resource mix. In addition to increasing their aggregate demand for electricity, the NOPR explained that customers, including major corporations, in many regions are increasingly demanding that load be served by renewable or non-emitting resources.²²⁹ Substantial evidence in the record supports the existence of this trend. Since 2014, for example, “commercial and industrial customers have contracted for more than 52 GW of clean energy[.]”²³⁰ Furthermore, this trend is accelerating. In 2021 alone, energy customers voluntarily contracted for “11.06 GW of clean energy.”²³¹ The record demonstrates that, going forward, this shift is projected to continue, as forecasts show that Fortune 1000 companies will have up to 85 GW of new demand for renewable energy to meet their public sustainability commitments for 2030.²³² As also noted in the NOPR, utilities in many regions have made commitments to procure most or all of their electricity from renewable or non-emitting resources. For example, Exelon,²³³ Dominion,²³⁴ AEP,²³⁵ and Southern²³⁶ have all committed to achieve net-zero emissions by 2050, and each has set an

(2022), <https://rhg.com/research/climate-clean-energy-inflation-reduction-act/>); NextEra Reply Comments at 5 (“The signing of the Inflation Reduction Act of 2022 . . . will only increase the demand for renewables in the coming years and accelerate corresponding demands on the transmission system.”).

²²⁹ NOPR, 179 FERC ¶ 61,028 at P 45.

²³⁰ Advanced Energy Buyers Initial Comments at 5 (citing Clean Energy Buyers Alliance, *State of the Market 2022*, <https://cebusers.org/state-of-the-market/>).

²³¹ Clean Energy Buyers Initial Comments at 7.

²³² Clean Energy Buyers Initial Comments at 7 n.13 (citing Clean Energy Buyers ANOPR Initial Comments at 21–22).

²³³ Exelon Initial Comments at 2 (“Exelon has established ambitious targets and aims to be a leader in clean energy by continuing to reduce its own greenhouse gas emissions, including reducing operations-driven emissions 50 percent by 2030, relative to a 2015 baseline, and achieving net-zero operations by 2050.” (citing Calvin Butler, Exelon Corporation, *We’re on the Path to Clean* (Apr. 2021), <https://www.exeloncorp.com/grid/were-on-the-path-to-clean>)).

²³⁴ Dominion Initial Comments at 3–4 (“Dominion Energy has committed to achieve net zero greenhouse gas emissions by 2050 and is investing in clean energy resources such as solar and wind.”).

²³⁵ AEP Initial Comments at 4 n.12 (“AEP’s goal is to reduce carbon emissions from directly owned generation by 80% by 2030 compared to 2000 levels and to achieve net-zero emissions by 2050.” (citing AEP, 2022 *Corporate Sustainability Report*, at 48 (2022), <https://www.aep.com/news/releases/read/8520/AEP-Releases-2022-Corporate-Sustainability-Report>)).

²³⁶ Southern Initial Comments at 14 (“By 2019, Southern Companies had already achieved a 44% reduction in greenhouse gas emissions in pursuit of its goals of a 50% reduction by 2030 and net zero by 2050.”).

interim goal to significantly reduce emissions by 2030. And, although utility commitments vary by utility and by region, the record shows that many utilities have announced some future emissions target.²³⁷

98. Furthermore, as noted in the NOPR,²³⁸ the resource mix is also being affected by the changing economics of the resources that comprise the resource mix.²³⁹

99. Together, trends in economics, growing demand, and Federal, federally-recognized Tribal, state, and local policies are already resulting in significant changes in the resource mix. The record shows that as of 2021, nearly 70% of capacity additions across the country were from new, utility-scale wind and solar resources.²⁴⁰ Meanwhile, most of the capacity retirements are, and are projected to continue to be, coal resources.²⁴¹ Based

²³⁷ See, e.g., SREA Initial Comments at 41–42 (“Major utilities in the South, including Entergy, Dominion Energy, Duke Energy, NextEra, Tennessee Valley Authority, and Southern Company have all announced some version of a net zero carbon emission plan or commitment.”).

²³⁸ NOPR, 179 FERC ¶ 61,028 at P 45 & n.72 (noting the average levelized cost of wind energy for commercial wind generation has decreased from \$90 per MWh in 2009, to \$35 per MWh in 2019 (citing Lawrence Berkeley National Laboratory, *Wind Energy Technology Data Update: 2020 Edition*, at 66 (Nov. 2020))); *id.* (noting that the average levelized power purchase agreement price for utility-scale solar generation has decreased from approximately \$160 per MWh in 2009, to approximately \$40 MWh in 2020 (citing Lawrence Berkeley National Laboratory, *Utility-Scale Solar Data Update: 2020 Edition*, at 32 (Nov. 2020))).

²³⁹ See ACOE ANOPR Initial Comments at app. 1, p. 22 (ACEG Jan. 2021 Planning Report) (“Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.”); Dominion Initial Comments at 19 (noting how, during the 2010s, the fracking revolution and advanced technology for natural gas combined cycle generation lead to a shift away from coal and nuclear as “baseload” fuels and how, today, renewable energy resources are likewise undergoing a similar expansion); Evergreen Action Initial Comments at 3 (“Rapid innovation has made wind and solar power the lowest-cost resource in many areas of the country[.]” (citing Univ. of Tex. at Austin Energy Inst., *Levelized Cost of Electricity in the United States by County* (2022), http://calculators.energy.utexas.edu/lcoe_map/#/county/tech); see also ACOE Reply Comments at 2 (“In all scenarios, building transmission that enables low-cost wind and other energy resources is often cheaper than the alternatives, such as use of higher-cost but local resources (and potentially additional storage).” (citing Paul Denholm, et al., National Renewable Energy Laboratory, *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*, at 47–78 (Sept. 2022))).

²⁴⁰ SREA Initial Comments at 1–2 (citing US Energy Info. Admin., *Today in Energy* (2021), <https://www.eia.gov/todayinenergy/detail.php?id=46416#>); see also AEE Initial Comments at 13 (noting that between 2011 and 2021, “renewable generation nearly doubled, from 12.5% to more than 20%.”).

²⁴¹ AEE Initial Comments at 12–13 (“From 2011 to 2021, the proportion of U.S. electricity generated by coal plants dropped by almost half, from 42%

on the record, those trends are projected to continue, with over 1,300 GW of wind, solar, and storage resources in interconnection queues across the country as of 2021.²⁴² With the passage of the Inflation Reduction Act in 2022, many analysts are predicting that the shift toward renewable resources will accelerate.²⁴³

100. In light of these changing demands on the transmission system, the record also affirms what the Commission has long recognized: regional transmission planning that identifies more efficient or cost-effective transmission solutions to needs helps to ensure cost-effective transmission

to under 22%” (citing U.S. Energy Info. Admin., *U.S. Electricity Generation by Major Energy Source, 1950–2021* (2022), <https://www.eia.gov/energyexplained/electricity/charts/generation-major-source.csv>); California Commission Initial Comments at 65 (citing FERC, *State of the Markets 2020* (Mar. 2021); Renewable Northwest Initial Comments at 36 (using IRP data to show that utilities in NorthernGrid plan to retire 6,573 MW of coal, 1,476 MW of natural gas, 10 MW of wind, and 18 MW of solar, by 2040). FERC’s *State of the Markets 2020* report stated that 9.6 GW of coal capacity retired in 2020, which had a noticeable effect on coal’s operating capacity share in most RTOs/ISOs. FERC, *State of the Markets 2020*, at 10, 12 (Mar. 2021). FERC’s *State of the Markets 2023* indicates that this trend is continuing, with coal generation declining 18.8% in 2023. FERC, *State of the Markets 2023*, at 4 (Mar. 2024). See also US DOE Initial Comments at App. B, pp. 8–9 (Rand et al., Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021* (Apr. 2021)).

²⁴² See US DOE Initial Comments app. B, at p. 26 (Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021* (Apr. 2022)) (noting that 676 GW of solar, 246 GW of wind, 213 GW of standalone battery capacity, and ~208 GW of hybrid battery capacity wait in interconnection queues across the U.S.). On the other hand, the number of coal and, relatedly, natural gas resources waiting to interconnect is limited. See *id.*; Colorado Consumer Advocates Initial Comments attach. 7, at p. 21 (“No new coal plants have been built for domestic utility electricity production since 2014[.]”); NESCOE Initial Comments at 15–16 (noting that new natural gas generation represented nearly 48% of the queue in 2017, but just 3% by March of 2022). Moreover, the updated version of the report to which US DOE cites indicates that the capacity of wind, solar, and storage in interconnection queues is still increasing. Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022* (Apr. 2023) (noting that 947 GW of solar, 300 GW of wind, 325 GW of standalone battery capacity, and ~358 GW of hybrid storage capacity, totaling over 1900 GW, wait in interconnection queues across the country).

²⁴³ ACOE Initial Comments at 1–2 & n.2 (“[P]rojecting annual additions increasing from 15 GW of wind and 10 GW of utility-scale solar PV in 2020 to an average of 39 GW/year of wind additions in 2025–2026 (~2x the 2020 pace) and 49 GW/year of solar (~5x the 2020 pace), with solar growth rates increasing thereafter.” (quoting REPEAT Project, *Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022*, at 15 (2022), https://repeatproject.org/docs/REPEAT_IRA_Preliminary_Report_2022-08-12.pdf)).

development for customers and can yield better returns for every dollar spent than localized or piecemeal transmission solutions.²⁴⁴ Conversely, inadequate or poorly designed transmission planning processes can lead to relatively inefficient or less cost-effective transmission investment, with customers footing the bill for piecemeal, inefficient, and less cost-effective transmission solutions designed to meet short-term or small-scale transmission needs. Given the magnitude of transmission investment needed to meet customers’ changing needs, it is essential that regional transmission planning be of sufficient scope and duration to help to ensure customers’ money is well-spent on transmission infrastructure that can efficiently and cost-effectively meet those needs. Unfortunately, we conclude that this is not the case today and that existing regional transmission planning processes are inadequate to address the emerging Long-Term Transmission Needs that are expected to increasingly drive transmission investment in the coming decades.

101. Experience with the implementation of Order No. 1000 over the last decade has highlighted a critical gap in the Commission’s existing

²⁴⁴ Order No. 1000, 136 FERC ¶ 61,051 at P 55 (“[T]he narrow focus of current planning requirements and shortcomings of current cost allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities.”); *id.* P 68 (concluding that reforms that require transmission providers to engage in regional transmission planning and evaluate proposed alternatives that “may resolve the region’s needs more efficiently or cost-effectively than solutions identified in the local transmission plans . . . will provide assurance that rates for transmission services on these systems will reflect more efficient or cost-effective solutions for the region.”); Order No. 890, 118 FERC ¶ 61,119 at P 524 (“[C]oordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis.”); see also ACOE Initial Comments at 6 (demonstrating that effective regional transmission planning could significantly reduce total electric system costs compared to electric system costs that result from intrastate planning (citing Brattle-Grid Strategies Oct. 2021 Report at 12)); R Street Initial Comments at 8 (“[H]olistic transmission planning could improve economic efficiencies and save billions of dollars For example, MISO’s 2022 long-range transmission plan results include \$10 billion in transmission projects that support interconnection of 53,000 megawatts of new renewable generation and reduces other costs by \$37–\$68 billion. PJM similarly identified \$3 billion in transmission upgrades that would save billions compared to the current practice of incremental upgrades through the interconnection process.” (citing Johannes Pfeifenberger, Brattle Group, *Planning for Generation Interconnection*, at 5 (May 31, 2022), <https://www.esig.energy/event/special-topic-webinar-interconnection-study-criteria> (citation omitted))).

transmission planning and cost allocation requirements. Notwithstanding the broad recognition that additional transmission infrastructure is needed to address the drivers noted above, regional transmission planning processes across the country have yielded only limited investments in regional transmission projects. As the Commission observed in the NOPR, investment in regional transmission facilities in some regions has declined compared to prior to Order No. 1000.²⁴⁵ Moreover, across all the non-RTO/ISO regions, there has not yet been a single transmission facility selected since implementation of Order No. 1000.²⁴⁶ The record also demonstrates that within some RTO/ISO regional transmission planning processes, even where investments through the regional transmission planning process do occur, much of that investment has been in transmission projects that only address immediate reliability needs.²⁴⁷ We find that this evidence supports our conclusion that existing regional transmission planning processes are not of sufficient scope and duration to adequately or consistently identify transmission needs and associated opportunities to more comprehensively evaluate and select more efficient or cost-effective transmission solutions to those needs.

102. Indeed, in the limited instances in which transmission providers have followed processes that share many of the elements of the long-term, forward-looking, and more comprehensive regional transmission planning this

²⁴⁵ NOPR, 179 FERC ¶ 61,028 at P 39 (citing ACEG Jan. 2021 Planning Report at 25 & fig. 8); see also ACOE ANOPR Initial Comments at 4 (“Despite the potential benefits, regional transmission investment has not increased and in some regions even has declined over the past decade.”) (citing ACEG Jan. 2021 Planning Report at 25)); State Agencies Initial Comments at 23 (“Regionally planned projects have [] declined in RTOs/ISOs” (citing John C. Gravan and Rob Gramlich, NRRI Insights, *A New State-Federal Cooperation Agenda for Regional and Interregional Transmission*, at 2 (Sept. 2021), <https://pubs.naruc.org/pub/FF5D0E68-1866-DAAC-99FB-A31B360DC685>)).

²⁴⁶ NOPR, 179 FERC ¶ 61,028 at P 39 (citing LS Power ANOPR Initial Comments App. I at 18 & n.57); FERC, Staff Report, *2017 Transmission Metrics*, at 19 (Oct. 6, 2017), <https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf>); see also Western PIOs Initial Comments at 28 (“The Western Regional Planning Groups, with the exception of the CAISO, have not developed new projects from their current Order 1000 transmission planning process.”).

²⁴⁷ Southwestern Power Group Initial Comments at 15; PIOs ANOPR Initial Comments at 93 & n.276; see also Ari Peskoe, *Is the Utility Syndicate Forever?*, 42 Energy L.J. 1, 56–57 (2021) (explaining, for example, that in ISO–NE, all but one of the transmission projects approved through the regional transmission planning process were immediate-need reliability projects).

order requires, customers have seen clear and quantifiable benefits. For example, as the Commission observed in the NOPR,²⁴⁸ MISO's Multi-Value Project (MVP) transmission planning process proactively planned over a 20-year period for two key drivers of transmission needs: the impacts of changing state laws on the resource mix, and a large increase in the number of generator interconnection requests. To mitigate the uncertainties associated with such long-term projections of transmission needs, MISO relied on scenarios to consider a range of potential future conditions²⁴⁹ and disclosed the assumptions and inputs underlying each scenario.²⁵⁰ The MVP process then identified a portfolio of transmission projects that were projected to provide multiple kinds of reliability and economic benefits under all the alternate future scenarios studied.²⁵¹ This process resulted in MISO identifying, evaluating, and selecting transmission facilities that are estimated to generate \$2.20 to \$3.40 of benefit per dollar invested.²⁵²

103. The benefits to transmission customers of long-term, forward-looking, and more comprehensive regional transmission planning, which we discuss further below, are thus well-documented but realized all too infrequently under existing regional transmission planning processes. Relatedly, the record demonstrates that a substantial amount of new transmission investment is occurring outside of regional transmission planning processes. Because these other processes—specifically, generator interconnection processes and local transmission planning processes—are generally designed to address discrete, shorter-term needs, and do not comprehensively assess either broader transmission needs or solutions to those needs, overreliance on those processes can result in relatively inefficient or less cost-effective transmission development for customers,²⁵³ which contributes to

rates for transmission that are unjust and unreasonable.

104. The record demonstrates that significant expansion of the transmission system is occurring through one-off, piecemeal, interconnection-related network upgrades constructed in response to individual generator interconnection requests.²⁵⁴ As the Commission observed in the NOPR, the evidence shows a sharp growth in both the total cost of interconnection-related network upgrades and in the cost of such upgrades relative to generation project costs.²⁵⁵ The record indicates that the average cost of interconnection-related network upgrades is increasing over time as the transmission system is fully subscribed and demand for interconnection service outpaces transmission investment. As highlighted in the NOPR,²⁵⁶ in 2020, MISO identified the need for nearly \$2.5 billion in interconnection-related network upgrades to interconnect just 9.2 GW of generation in MISO South, and MISO expects to need over \$3 billion in interconnection-related network upgrades for interconnection in MISO West.²⁵⁷ Similarly, SPP identified the need for \$4.6 billion in interconnection-related network upgrades to interconnect just 10.4 GW of new generation.²⁵⁸

105. Record evidence also shows that increases in interconnection costs are being driven, in many cases, by an expansion in the scope and complexity of interconnection-related network upgrades.²⁵⁹ The Commission noted in

“snowballing inefficiencies created by numerous small-scale transmission band-aids, unfit to address broader generation trends, translate into excessive, unjust, and unreasonable rates borne by an already overburdened populace.”).

²⁵⁴ Pine Gate Initial Comments at 6, 8–10; PIOs Initial Comments at 9 (noting how most transmission planning is done through the generator interconnection process or local transmission planning).

²⁵⁵ NOPR, 179 FERC ¶ 61,028 at P 37.

²⁵⁶ *Id.* PP 37–38.

²⁵⁷ ACOE ANOPR Initial Comments at 10 (citing ICF Sept. 2021 Interconnection Report at 2).

²⁵⁸ *Id.* (citing ICF Sept. 2021 Interconnection Report at 3–4).

²⁵⁹ *See, e.g.*, US DOE Initial Comments at 8 & n.20 (citing Jay Caspary et al., ACEG, *Disconnected: The Need for a New Generator Interconnection Policy*, at 13–16 (2021), <https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf>) (ACEG 2021 Interconnection Report); Will Gorman et al., *Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy*, 135 Energy Policy 110994 (2019), <https://www.sciencedirect.com/science/article/pii/S0301421519305816>); ACEG 2021 Interconnection Report at 13 (“[T]he costs for integrating new resources in MISO are rising substantially relative to previous years, indicating that the large-scale network has reached its capacity

the NOPR, for example, that interconnection-related network upgrade costs in MISO West went from approximately \$300/kW in 2016 to nearly \$1,000/kW in 2017.²⁶⁰ The trend is evident in other parts of the country as well.²⁶¹ The costs of interconnection-related network upgrades are, in many cases, an ever-growing percentage of the total capital costs of new generation projects. According to one report, interconnection costs for new renewable resources were less than 10% of total generation project costs until a few years ago, but recently these costs have risen to as much as 50%–100% of the total generation project costs.²⁶² At the

and needs to expand to connect more generation. In other words, much more than ‘driveway’ type facilities are needed; larger roads and highways are required to alleviate the traffic [H]istorically, interconnecting wind projects have incurred interconnection costs of \$0.85 per megawatt hour (MWh) or \$66 per kilowatt (kW). However, newly proposed wind projects now face interconnection costs that are nearly five times higher, at \$4.05/MWh or \$317/kW.”); *id.* at 14 (“New solar projects in MISO South have much higher upgrade costs. The most recent 2019 system impact study for solar projects in MISO South estimated upgrade costs to total \$307/kW, with upgrade costs for individual interconnection requests as high as \$677/kW.”); *id.* (“The same trend of rising network upgrade cost assignments is occurring in PJM. Historically, the leveled costs for constructed wind and solar projects were \$0.25/MWh and \$1.72/MWh, respectively, or \$19.07 kW and \$61.83/kW, respectively . . . costs for newly proposed wind and solar projects, however, have now risen to \$0.69/MWh and \$3.66/MWh, respectively or \$0.54/kW and \$131.90/kW, respectively—more than a 100 percent increase.”).

²⁶⁰ NOPR, 179 FERC ¶ 61,028 at P 38 (citing ACEG Jan. 2021 Interconnection Report at 14; NextEra ANOPR Initial Comments at 16 (citing Midcontinent Indep. Sys. Operator, *MISO 2020 Queue Outlook*, at 9 (2020), <https://cdn.misoenergy.org/MISO2020InterconnectionQueueOutlook445829.pdf>)).

²⁶¹ NOPR, 179 FERC ¶ 61,028 at P 38 (showing that, as of 2019, interconnection costs in PJM for constructed wind and solar projects were \$19.07/kW and \$61.83/kW, respectively, as compared to a greater than 100% increase to \$54/kW and \$131.90/kW, respectively, for projects newly proposed today) (citing *e.g.*, ACEG Jan. 2021 Interconnection Report at 14 & tbl.2); NextEra ANOPR Initial Comments at 16–17 (stating that interconnection-related network upgrade cost estimates have nearly tripled for newly proposed wind projects, and more than doubled for solar projects in PJM); *see also* ACEG Jan. 2021 Interconnection Report at 16 (illustrating an increase in average interconnection-related network upgrade costs in NYISO from \$67/kW in 2013 to \$124/kW in 2019). *Compare* ACEG Jan. 2021 Interconnection Report at 15 (identifying interconnection-related network upgrade costs in 2013 in SPP as \$89/kW), with ICF Sept. 2021 Interconnection Report at 2 (citing interconnection-related network upgrade costs of \$448/kW for interconnection customers studied in SPP’s system impact study published in April 2021)).

²⁶² NOPR, 179 FERC ¶ 61,028 at P 38 (citing ACEG Jan. 2021 Interconnection Report at 6); *id.* (stating that the rising interconnection costs of wind projects in MISO recently reached approximately 23% of the capital cost of the project) (citing ACEG Jan. 2021 Interconnection Report at 13)); *id.* (identifying the increase in interconnection-related network upgrade costs in SPP between 2013 and

²⁴⁸ NOPR, 179 FERC ¶ 61,028 at PP 30–31 (citing Midcontinent Indep. Sys. Operator, *RGOS: Regional Generation Outlet Study*, at 2 (Nov. 2020)).

²⁴⁹ *Id.* P 31 (citing MTEP2017 Review at 26–29).

²⁵⁰ *Id.* (citing MTEP2017 Review at 16).

²⁵¹ *Id.* (citing MTEP2017 Review at 13).

²⁵² *Id.* P 30 (citing MTEP2017 Review at 4).

²⁵³ ACOE Initial Comments at 4–5 (citing Brattle-Grid Strategies Oct. 2021 Report at 3); Clean Energy Associations Initial Comments at 5 (explaining that proactive, forward-looking transmission planning processes can reduce costs by nearly half as compared to incremental and reactive transmission planning processes); Ørsted Initial Comments at 5 (explaining that failure to proactively plan for offshore wind results in suboptimal transmission development, which can increase costs to ratepayers); Southeast PIOs Reply Comments at 2 (explaining that in the Southeast,

same time, interconnection-related network upgrades have frequently transitioned from primarily small transmission facilities that serve the needs of a limited number of interconnection customers to the size and scope of what have traditionally been considered high voltage transmission facilities. For example, interconnection-related network upgrades have recently included demolishing and rebuilding multiple 500 kV transmission lines²⁶³ and constructing long, double-circuit, 765 kV transmission lines,²⁶⁴ all at significant cost to the interconnection customer initially—and ultimately to consumers.

106. Unlike regional transmission planning processes, however, the generator interconnection process is not designed to consider how to address transmission needs more efficiently or cost-effectively beyond the discrete interconnection request (or requests) being studied. Therefore, the generator interconnection process does not look at time horizons beyond the specific interconnection request(s) being studied, comprehensively assess any transmission needs beyond those created by the specific interconnection request(s), or achieve the economies of scale in transmission investment that long-term, forward-looking, and more comprehensive regional transmission planning processes can provide.²⁶⁵

2017 as representing an increase from around 8% to over 43% of the capital cost of wind generation (citing ACEG Jan. 2021 Interconnection Report at 15); NextEra ANOPR Initial Comments at 17 (similar)).

²⁶³ NOPR, 179 FERC ¶ 61,028 at P 38 (describing interconnection-related network upgrades for a 120 MW solar plus storage project in southern Virginia to interconnect to PJM that cost as much as \$12,086/kW (citing ACEG Jan. 2021 Interconnection Report at 15)).

²⁶⁴ NOPR, 179 FERC ¶ 61,028 at P 38 (describing one interconnection-related network upgrade in SPP identified in the system impact study published in April 2021) (citing ACEG Jan. 2021 Interconnection Report at 15); ICF Sept. 2021 Interconnection Report at 3 (same); NextEra ANOPR Initial Comments at 17 (same). In 2017, for example, SPP included a 165-mile, \$1.34 billion double circuit 765 kV line in its Definitive Interconnection System Impact Study. See ACORE ANOPR Initial Comments Ex. 5, ICF Sept. 2021 Interconnection Report at 4.

²⁶⁵ Anbaric Initial Comments at 5; Clean Energy Associations Initial Comments at 15 (noting the reactive nature of generator interconnection processes); Exelon Initial Comments at 5 (explaining that the “project-by-project approach of developing [interconnection-related] network upgrades” using the generator interconnection processes will likely not result in efficient or cost-effective outcomes given the ongoing changes in the resource mix and demand); Pine Gate Initial Comments at 9 (explaining how piecemeal approaches to transmission planning, like the generator interconnection process, result in inefficiently small upgrades (citing ACEG Jan. 2021 Interconnection Report at 7)); PIOs Initial

107. We acknowledge that the Commission recently issued Order No. 2023, which requires transmission providers to reform their generator interconnection processes. But while Order No. 2023 aims to improve the efficient processing of interconnection queues, it does not attempt to remedy the discrete deficiency addressed in this final order: that existing regional transmission planning and cost allocation requirements do not require transmission providers to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Instead, Order No. 2023 seeks to ameliorate the fact that existing generator interconnection procedures and agreements were “insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner[.]”²⁶⁶ The interconnection queue backlogs and delays that were the Commission’s focus in Order No. 2023 have arisen, in part, due to deficiencies in the existing transmission planning requirements. But the Commission found issues regarding the coordination between transmission planning and generator interconnection processes were beyond the scope of Order No. 2023 and, therefore, the Commission addressed only interconnection queue processes rather than also addressing transmission planning requirements.²⁶⁷ Consequently, this final order addresses a root cause of interconnection backlogs and delays that Order No. 2023 did not—the failure of transmission providers to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Accordingly, the need to reform this deficiency persists

Comments at 10; SEIA Initial Comments at 2; Southeast PIOs Initial Comments at 37 (“The lack of any regular, formal proceeding to consider Alabama Power’s comprehensive facility investment plan is troubling and ensures that both generation and transmission are considered on a project-by-project basis. This piecemeal approach to addressing transmission needs for individual generation resource decisions will cause sticker-shock every time and an institutional aversion to broader transmission investment, especially when transmission benefits are expressly ignored.”).

²⁶⁶ Order No. 2023, 184 FERC ¶ 61,054 at P 36.

²⁶⁷ Order No. 2023, 184 FERC ¶ 61,054 at PP 1741, 1743 (finding that, although “several commenters argue in favor of greater coordination between generator interconnection and transmission planning or identify interconnection as a matter requiring interregional planning,” those comments were beyond the scope of that rulemaking proceeding and noting that “the Commission proposed reforms related to coordination between regional transmission planning and cost allocation and generator interconnection in” the docket for this final order).

despite the Commission’s reforms required by Order No. 2023.

108. While some commenters argue that transmission providers do not rely too heavily on the generator interconnection process to build transmission facilities,²⁶⁸ we find that the record indicates otherwise. Specifically, as discussed above, the increase in both the total and average cost of interconnection demonstrates how much transmission investment is occurring on a one-off, incremental basis through generator interconnection processes.²⁶⁹ The Commission has consistently and repeatedly found that interconnection-related network upgrades provide systemwide benefits,²⁷⁰ a finding which courts have upheld.²⁷¹ In turn, we find that increasingly relying on interconnection customers’ interconnection-related network upgrades to expand the capacity of the transmission system is inefficient and leads to less cost-effective transmission development than would result from long-term, forward-looking, and more comprehensive regional transmission planning, to the detriment of customers.

109. Separately, the record here also substantiates the NOPR’s preliminary

²⁶⁸ Mississippi Commission Initial Comments at 9; North Carolina Commission and Staff Initial Comments at 5; Southern Initial Comments at 38–40.

²⁶⁹ New Jersey Commission Initial Comments at 6–7 (noting that interconnecting 87.1 GW of capacity, which is needed to meet the PJM states’ offshore wind and renewable portfolio standards goals, through the interconnection queue process alone is projected to cost \$36 billion); US DOE Initial Comments at 8 (citing ACEG 2021 Interconnection Report at 13–16 (2021)).

²⁷⁰ See, e.g., *Duke Energy Progress, LLC*, 181 FERC ¶ 61,229, at P 17 (2022) (rejecting Duke’s claim that “its customers reap no benefits from network upgrades that must be constructed on Duke’s affected system” because “Duke’s characterization disregards the existence of any benefits to its customers from the network upgrades”); *ISO New England Inc.*, 150 FERC ¶ 61,209, at P 386 (2015) (noting that there “is a presumption that transmission system enhancements benefit all members of an integrated transmission system”); *Pac. Gas & Elec. Co.*, 106 FERC ¶ 61,144, at P 22 (2004) (explaining that “the integrated grid is a single interconnected system serving and benefitting all transmission customers”); *Pub. Serv. Co. of Colo.*, 62 FERC ¶ 61,013, at 61,061 (1993) (“The Commission has reasoned that, even if a customer can be said to have caused the addition of a grid facility, the addition represents a *system* expansion used by and benefitting *all* users due to the integrated nature of the grid.” (emphasis in original)).

²⁷¹ See, e.g., *Nat’l. Ass’n of Regul. Util. Comm’rs v. FERC*, 475 F.3d 1277, 1285 (D.C. Cir. 2007) (“We have endorsed the approach of ‘assign[ing] the costs of system-wide benefits to all customers on an integrated transmission grid.”); *W. Mass. Elec. Co. v. FERC*, 165 F.3d 922, 927 (D.C. Cir. 1999) (“When a system is integrated, any system enhancements are presumed to benefit the entire system.”); *City of Holyoke Gas & Elec. Dep’t v. FERC*, 954 F.2d 740, 742–43 (D.C. Cir. 1992); *Me. Pub. Serv. Co. v. FERC*, 964 F.2d 5, 8–9 (D.C. Cir. 1992).

finding that the majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities.²⁷² Commenters explain that, in RTO/ISO regions, one half of the nearly \$70 billion in aggregate transmission investments by Commission-jurisdictional transmission providers between 2013 and 2017 was approved outside of regional transmission planning processes.²⁷³ This investment trend is continuing and accelerating. For example, in 2019, PJM approved 383 transmission-owner planned supplemental projects at a total cost of \$3.75 billion, compared to only 80 regionally planned baseline projects at a total cost of \$1.27 billion. Then, in 2020, PJM approved 236 supplemental projects at a total cost of \$4.7 billion, compared to only 43 regionally planned baseline projects at a total cost of \$413 million.²⁷⁴ In MISO, baseline reliability projects and other local transmission projects have grown dramatically since 2010 and constituted 100% of approved transmission between 2018 and 2020 and 80% since 2010.²⁷⁵ From 2019 to 2021, 63% of transmission investment by the three largest transmission owners in CAISO was in local transmission projects, and Pacific Gas and Electric forecasts that of the \$13 billion it will spend on capital additions between 2022 and 2027, approximately 84% will be on local transmission projects.²⁷⁶ In ISO-NE, spending on in-kind transmission replacements, which are not part of the regional transmission planning process, has been significant. Between 2016 and 2022, over \$2.5 billion has been spent on in-kind replacement projects that have entered service and, as of 2022, an additional \$3.122 billion of in-kind replacement projects had been proposed, planned, or were under construction.²⁷⁷

110. As with the growing reliance on the generator interconnection process to identify needed transmission system improvements, local transmission planning, with its focus on the needs of individual utility footprints, does not necessarily provide sufficient, comprehensive analysis of broader

regional transmission needs. Similarly, local transmission planning processes and in-kind replacement processes do not generally assess transmission needs based on a forward-looking multi-scenario assessment that more comprehensively accounts for the benefits of transmission infrastructure.²⁷⁸ Therefore, transmission expansion in this incremental manner also misses the potential for transmission providers to identify, evaluate, and select more efficient or cost-effective transmission facilities to solve transmission needs, as well as to afford system-wide benefits that may not be achieved through piecemeal, one-off local transmission facilities. As stated above, the result is relatively inefficient or less cost-effective transmission development for customers, which contributes to rates for transmission that are unjust and unreasonable.

111. To be clear, our findings here are not intended to call into question the justness and reasonableness of either generator interconnection processes or local transmission planning processes, which each serve important roles in ensuring reliability and integrating new resources onto the transmission system.²⁷⁹ Rather, the trends regarding use of these processes, as well as in-kind replacement processes, provide additional evidence to support our finding that existing regional transmission planning and cost allocation requirements are inadequate without reform. As discussed further in the next section, we conclude that the record regarding the current and projected transmission landscape—including the investment trends and changing drivers of that investment detailed above—highlights critical deficiencies in the Commission's current regional transmission planning and cost allocation requirements. In this final order, we address those deficiencies to help to ensure that customers receive the benefits of long-term, forward-looking, and more comprehensive regional transmission planning.

2. Unjust, Unreasonable, and Unduly Discriminatory or Preferential Commission-Jurisdictional Transmission Planning and Cost Allocation Processes

112. Based on the record, including comments submitted in response to the NOPR, as discussed below, we find that there is substantial evidence to support the determination that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation to meet Long-Term Transmission Needs is not occurring on a consistent and sufficient basis. We find that the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning processes is resulting in piecemeal transmission expansion to address relatively near-term transmission needs. We find that the status quo approach results in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. This dynamic results in, among other things, transmission customers paying more than is necessary or appropriate to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.

113. We therefore adopt, as modified by the discussion herein, the preliminary findings of the NOPR concerning the need for reform²⁸⁰ and, pursuant to FPA section 206, conclude that revisions to the Commission's regional transmission planning and cost allocation requirements are necessary to ensure that Commission-jurisdictional rates, terms, and conditions are just, reasonable, and not unduly discriminatory or preferential. We find that, as stated in the NOPR,²⁸¹ absent the reforms instituted by this final order, regional transmission planning processes will continue to fail to identify, evaluate, and select regional transmission facilities that can more efficiently or cost-effectively meet Long-Term Transmission Needs, requiring customers to pay for relatively inefficient or less cost-effective transmission development.

²⁷² NOPR, 179 FERC ¶ 61,028 at PP 39–40.

²⁷³ PIOs Initial Comments at 9.

²⁷⁴ PIOs ANOPR Initial Comments at 31–44; *see also* Ohio Consumers Initial Comments at 5 (“Since 2017, in Ohio, less than 25% of the new investment in transmission has been associated with large regional transmission projects needed for reliability or economic efficiency.”).

²⁷⁵ *See* PIOs Initial Comments at 10 n.31 (citing PIOs ANOPR Initial Comments at 49 (citing Brattle-Grid Strategies Oct. 2021 Report at iii, 2)).

²⁷⁶ *See* California Commission Initial Comments at 109–110.

²⁷⁷ NESCOE Reply Comments at 6.

²⁷⁸ PIOs ANOPR Initial Comments at 33–34 (citing ACEG Jan. 2021 Planning Report); ACEG Jan. 2021 Planning Report at 98–99.

²⁷⁹ As discussed below, we separately find that specific existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are unjust, unreasonable, and unduly discriminatory or preferential. *See infra* Local Transmission Planning Inputs in the Regional Transmission Planning Process section.

²⁸⁰ NOPR, 179 FERC ¶ 61,028 at PP 28–55.

²⁸¹ NOPR, 179 FERC ¶ 61,028 at P 33.

114. Based on the record, including the comments submitted in response to the NOPR, we find that there is substantial evidence to support the conclusion that deficiencies in the Commission's existing regional transmission planning and cost allocation requirements are resulting in Commission-jurisdictional rates that are unjust, unreasonable, and unduly discriminatory or preferential. Specifically, we find that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We find that these deficiencies render Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable because they result in transmission providers failing to identify Long-Term Transmission Needs, to evaluate and select more efficient or cost-effective transmission solutions to meet those transmission needs, and to allocate the costs of transmission facilities selected to meet those transmission needs in a manner that is at least roughly commensurate with benefits. Below, we address each deficiency in turn.

115. The first deficiency is that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to perform a sufficiently long-term assessment of transmission needs. This deficiency is present in multiple aspects of existing regional transmission planning processes, from the degree to which planning studies that identify transmission needs are sufficiently forward looking, to whether forward-looking assessments actually inform the evaluation, selection, and eventual cost allocation of regional transmission facilities. The record demonstrates that, under existing regional transmission planning and cost allocation processes, transmission providers typically identify and plan for transmission needs using a relatively near-term transmission planning horizon. Specifically, commenters have noted that most transmission planning regions do not plan beyond a 10-year transmission planning horizon. For

example, commenters point out that ISO-NE, SERTP, and NorthernGrid plan using a 10-year transmission planning horizon,²⁸² while PJM notes that it plans using two different transmission planning horizons: a 5-year transmission planning horizon for what it refers to as its short-term transmission planning process and a 6-to-15-year transmission planning horizon for what it refers to as its intermediate-term transmission planning process.²⁸³ While it is reasonable and necessary for regional transmission planning and cost allocation processes to include a near-term study of the transmission system, the absence of any consistent and sufficient longer-term assessment of transmission needs prevents transmission providers from identifying Long-Term Transmission Needs and considering regional transmission facilities that may be more efficient or cost-effective solutions to address those needs.²⁸⁴

116. This lack of a longer-term assessment of transmission needs is particularly problematic for a few reasons. First, shorter-term transmission planning fails to take advantage of the potential for efficiencies or economies of scale that regional transmission facilities can provide by allowing fewer or better designed transmission facilities to meet multiple transmission needs.

²⁸² Massachusetts Attorney General Initial Comments at 25 ("For example, the Commission's proposal to increase the required long-term transmission planning horizon to at least 20 years with 3-year reassessments would double the current long-term planning horizon for ISO-NE."); Renewable Northwest Initial Comments at 12 (citing Brattle-Grid Strategies Oct. 2021 Report at 15); Southeast PIOs Initial Comments at 12 ("The 'independent reliability planning studies . . . start with the combined local transmission plans of participating utilities,' and the results comprise the ten-year regional transmission plan." (citation omitted)); Western PIOs Initial Comments at 8–9 ("NorthernGrid conducts transmission reliability plans on a two-year cycle, with each plan covering a 10-year time horizon."); *see also* ITC Initial Comments at 9 (referring to the "broad use of a 10-year planning horizon in the existing transmission planning processes of many major planning regions[.]").

²⁸³ PJM Initial Comments at 2 n.4.

²⁸⁴ *See, e.g.,* MISO ANOPR Reply Comments at 5 ("[G]iven long-term needs of an evolving system, additional transmission is necessary to reliably serve customers now and into the future. These challenges require immediate action and further delay only increases the risk that system enhancements may not be in place in the timeframe needed."); PIOs Initial Comments at 13 ("[A] short-term outlook under-forecasts longer-term transmission needs, preventing the development of more cost-effective transmission facilities, and fails to consider how the needs of the transmission system are shifting[.]"); US DOE ANOPR Initial Comments at 10 (stating that failure to plan transmission far enough ahead results in "adverse implications for system reliability, resilience, consumers' electricity rates, and the achievement of clean energy goals.").

For example, shorter-term transmission planning fails to provide the opportunity for transmission providers to identify, evaluate, and select regional transmission facilities that could address multiple transmission needs over various time horizons.²⁸⁵ Moreover, shorter-term transmission planning fails to create opportunities to "right size" the replacement of aging transmission facilities to address multiple transmission needs over the longer term.²⁸⁶ Second, constructing large (e.g., high voltage or long distance) transmission facilities comes with long lead times: planning, permitting, and building regional transmission facilities can often take more than ten years.²⁸⁷ As an example, the MVP initiative in the MISO region took a decade to move from approval by the MISO Board of Directors in 2011 to completion of most of the projects by 2021, and this period of 10 years does not even account for the significant transmission facility development efforts that occurred prior to the MISO Board of Directors' approval.²⁸⁸ Finally, the useful life of

²⁸⁵ ACORE Initial Comments at 4 ("The narrowly focused current approaches [to transmission planning] do not identify opportunities to take advantage of the large economies of scale in transmission that come from 'up-sizing' reliability projects to capture additional benefits, such as congestion relief, reduced transmission losses, and facilitating the more cost-effective interconnection of the renewable and storage resources needed to meet public policy goals." (quoting Brattle-Grid Strategies Oct. 2021 Report at 3)); PIOs ANOPR Initial Comments at 10–11; SEIA ANOPR Initial Comments at 14.

²⁸⁶ ACORE Initial Comments at 4 ("[I]n-kind replacement of aging existing facilities misses opportunities to better utilize scarce rights-of-way for upsized projects that can meet multiple other needs and provide additional benefits, thus driving up costs and inefficiencies." (quoting Brattle-Grid Strategies Oct. 2021 Report at 3)). PJM's long-term assessment of the transmission system ostensibly uses a 15-year transmission planning horizon, for example, but does not account for changes to the generation mix beyond a 5-year period. *See* Concerned Scientists ANOPR Initial Comments at 10 & n.11 ("Generation additions are unchanged in the 15-year study period, as the input assumption has no additional information that would expand the set of generators included in the forecast."); PSEG ANOPR Initial Comments at 11 (stating that "in practice only new resources that are near the end of the interconnection queue process and have signed an Interconnection Service Agreement are considered in the RTEP base case.").

²⁸⁷ AEP Initial Comments at 11; Nevada Commission Initial Comments at 7 n.24 (noting that it took over seven years between the request to include a transmission line in an Integrated Resource Plan (IRP) and the in-service date, which did not include the lead time for developing the underlying application) PIOs Initial Comments at 14 ("[A] 20-year planning horizon was necessary given the time needed to site, permit, and construct transmission facilities or because states have longer-term public policy goals."); Renewable Northwest Initial Comments at 5; SEIA Initial Comments at 6.

²⁸⁸ AESL Consulting, *A Transmission Success Story: The MISO MVP Transmission Portfolio*, at 39 (2021).

transmission assets generally far exceeds even 20 years, so a 10-year transmission planning horizon is much too short to capture all of the benefits that regional transmission facilities can provide.²⁸⁹

117. Thus, relying solely on shorter-term transmission planning and studies fails to identify Long-Term Transmission Needs and, consequently, undervalues or entirely ignores the benefits of transmission investments to meet those needs. Moreover, the likelihood that near-term assessments will fail to identify Long-Term Transmission Needs and more efficient or cost-effective regional transmission facilities to meet those needs is higher during periods of rapid change, as the electric sector is now experiencing, during which the need for transmission infrastructure is expected to grow considerably.²⁹⁰ We find that continuing with the status quo approach is resulting in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates.²⁹¹ As a result, among other things, customers are paying more than necessary or appropriate to meet their transmission needs, forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments and, in turn, renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.

118. The second deficiency is that the Commission's existing regional transmission planning and cost allocation requirements fail to require transmission providers to account adequately on a forward-looking basis

for known determinants of Long-Term Transmission Needs. This deficiency is related to the first deficiency in the sense that both relate to the failure of the existing transmission planning requirements to require transmission providers to adequately plan for the foreseeable future. We find that, even following Order Nos. 890 and 1000, transmission providers have adopted widely divergent approaches to determining the factors that are relevant to identifying transmission needs within regional transmission planning.²⁹² Specifically, as commenters note, some existing regional transmission planning processes ignore trends in future generation and the impact of extreme weather.²⁹³ Other commenters note that certain regional transmission planning processes ignore state laws or utility goals.²⁹⁴ In addition to failing to

²⁹² ELCON Initial Comments at 3 (“While regional differences are important to consider, too much flexibility was provided to transmission providers in Order No. 1000 that . . . created a patchwork of planning processes further complicating planning and fostering additional balkanization of the grid[.]”); NOPR, 179 FERC ¶ 61,028 at P 50.

²⁹³ GridLab Initial Comments at 4–5 (noting that SPP does not consider extreme weather events in its transmission plan); Grid Strategies July 2021 Extreme Weather Report at 5 (“[T]ransmission’s value for making the grid more resilient against severe weather and other unexpected threats is not typically accounted for in transmission planning and cost allocation analyses. Grid operator transmission planning processes typically assume normal electricity supply and demand patterns, and in most cases do not account for the value of transmission for increasing resilience.”); Renewable Northwest Initial Comments at 4, 8 (explaining that regional transmission planning in the Pacific Northwest does not model extreme weather events and generally does not reflect publicly available data such as utility IRPs or carbon reduction goals); *see also* Brattle-Grid Strategies Oct. 2021 Report at 36 (stating that production cost simulations that are typically used to estimate the economic benefit of regional transmission facilities assume no extreme weather events); SPP Market Monitor ANOPR Initial Comments at 3 & n.5 (describing that even SPP’s more forward-looking scenario analysis of an emerging technology case in its Integrated Transmission Plan presently underestimates the actual growth of renewables so much that “[w]ind capacity in service today (29.8 GW) already exceeds wind levels projected in both 2019 ITP futures that go out to 2029”).

²⁹⁴ Acadia Center and CLF Initial Comments at 1 (“Order No. 1000 has failed to require public utility transmission providers to align their transmission planning and funding processes with state policies and objectives.” (citing Regulatory Assistance Project, *FERC Transmission: The Highest-Yield Reforms*, at 4 (July 2022), <https://www.raponline.org/wp-content/uploads/2023/09/rap-littell-prause-weston-FERC-transmission-highest-yield-reforms-2022-july.pdf>)); Renewable Northwest Initial Comments at 12 (citing Brattle-Grid Strategies Oct. 2021 Report at 15, which states that WestConnect, for example, does not include planning inputs that extend beyond generic, baseline projects nor “knowable information about enacted public policy mandates, publicly stated utility plans, and/or consumer procurement targets[.]”); SREA Initial Comments at 25 (stating that “SERTP relies entirely on member utilities to self-nominate transmission study requests regarding

adequately account for factors that shape the resource mix, commenters also assert that current regional transmission planning processes fail to account for factors that will shape future load, particularly new loads associated with electrification trends like, for example, electric vehicles²⁹⁵ and data centers.²⁹⁶ Although transmission providers in some transmission planning regions account for a wider range of the factors that drive Long-Term Transmission Needs when performing regional transmission planning studies than do others,²⁹⁷ we find that transmission providers are not consistently or sufficiently accounting on a forward-looking basis for the known determinants of Long-Term Transmission Needs or accounting for such known determinants in a manner that ensures the identification and evaluation of more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.

119. We recognize there is inherent uncertainty in forecasting,²⁹⁸ and we

public policy, meaning if utilities do not provide recommendations or requests, no SERTP study is completed. For instance, in 2021, SERTP stated, “[t]he SERTP did not receive any input or proposals for possible transmission needs driven by Public Policy Requirements for the 2021 planning cycle. Therefore, no possible transmission needs driven by Public Policy Requirements have been identified for further evaluation of potential transmission solutions in the 2021 SERTP planning cycle.” (emphasis in original).

²⁹⁵ *See, e.g.*, Clean Energy Buyers Initial Comments at 7–8; National Grid Initial Comments at 8; *see also* AEE ANOPR Initial Comments at 18 (stating that MISO projects electrification effects on load in its long-term regional transmission planning, but how other transmission providers account for electrification trends is not consistent or transparent).

²⁹⁶ *See supra* note 2166; Rocky Mountain Institute Supplemental Comments at 1 (“Technology companies have begun requesting large interconnections for data centers that require increased electricity supply to power generative artificial intelligence.”); WIRES Supplemental Comments at attach. 1, p. 36 (Rob Gramlich, et al., *Fostering Collaboration Would Help Build Needed Transmission* (Feb. 2024)) (“Load growth is rising in much of the country, and it is happening in a way that is hard for any single entity to assess on their own. It varies by local area due to factors such as manufacturing plant and data center additions, plus expectations for end-use electrification and penetration of electric vehicles.”).

²⁹⁷ *See, e.g.*, Renewable Northwest Initial Comments at 11, 14–15 (discussing how the MISO transmission planning process accounts for the future resource mix); Western PIOs Initial Comments at 23–24, 26–27 (explaining forward-looking aspects of the CAISO transmission planning process).

²⁹⁸ We acknowledge NRG’s comment that forecasting is inherently uncertain. NRG Initial Comments at 10–12. Sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation, however, is better than a lack of planning. The Commission may, by applying its expertise and experience to the record, determine what type and amount of transmission planning results in a just and

²⁸⁹ SEIA Initial Comments at 6; US DOE Initial Comments at 33 (noting that transmission assets can have a useful life of at least 40 years).

²⁹⁰ US DOE ANOPR Initial Comments at 10 (“Relying on successive small transmission expansion projects to meet foreseeable long-term needs may lead to the need for expensive retrofits (at customers’ expense) at a later date. Economies of scale and network economies suggest that an initial larger-scale buildout will often represent a lower-cost solution.”); Midcontinent Independent System Operator, *MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report*, at 6 (July 28, 2022), <https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf> (“While the Tranche 1 Portfolio is the result of MISO’s long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward.”).

²⁹¹ *See, e.g.*, S.C. Pub. Serv. Auth., 762 F.3d at 56–59 (explaining that transmission planning processes are practices affecting rates pursuant to Section 206 of the FPA).

agree with Industrial Customers that current transmission planning is based on known and measurable factors.²⁹⁹ However, we find, based on this record, that the universe of known and measurable factors that drive regional transmission needs extends beyond those that transmission providers currently consider as part of their regional transmission planning processes. Specifically, the record demonstrates that a multitude of factors like reliability needs driven by the impact of extreme weather, trends in future generation additions and retirements, load growth, Federal, federally-recognized Tribal, state, and local laws, and utility goals increasingly shape Long-Term Transmission Needs, are known and identifiable, and have reasonably predictable effects, especially in the aggregate.

120. As noted above, the record shows that the increasing frequency, duration, and intensity of extreme weather events are driving changes in Long-Term Transmission Needs to maintain system reliability.³⁰⁰ Additionally, demand growth is a major driver of Long-Term Transmission Needs, and contrary to commenter assertions,³⁰¹ the record shows that evolving trends in load

reasonable rate. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55 (“[I]n rate-related matters, the court’s review of the Commission’s determination is particularly deferential because such matters are either fairly technical or ‘involve policy judgements that lie at the core of the regulatory mission.’” (citing *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1347 (D.C. Cir. 2009))). “The court owes the Commission ‘great deference’ in this realm because ‘[t]he statutory requirement that rates be ‘just and reasonable’ is obviously incapable of precise judicial definition’ and ‘the Commission must have considerable latitude in developing a methodology responsive to its regulatory challenge[.]’” *Id.* (citing *Morgan Stanley Cap. Grp. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 532 (2008); *Am. Pub. Gas Ass’n v. FPC*, 567 F.2d 1016, 1037 (D.C. Cir. 1977)).

²⁹⁹ Industrial Customers Initial Comments at 11.
³⁰⁰ ACEG Initial Comments at 63 (“[T]he need to improve regional and interregional planning arises from the transformative changes occurring with respect to resource diversity, energy market efficiencies, technological changes, operational innovations and resiliency to withstand severe weather events. If transmission facilities are not constructed, these are all benefits that would otherwise be forfeited.”); NERC Initial Comments at 6; Evergreen Action Initial Comments at 2 (“[A]dditional transmission built under improved planning procedures would [] create large reliability benefits. With increasing extreme weather events due to climate change—including wildfires, winter storms, hurricanes, and more—additional transmission infrastructure and grid improvements are increasingly necessary for resilience purposes.”); WE ACT Initial Comments at 2 (“Requiring public utility transmission providers to consider extreme weather events in Long-Term Regional Transmission Planning is a positive step towards addressing grid reliability in the face of more frequent and intensifying weather events.”).

³⁰¹ See, e.g., Industrial Customers Initial Comments at 8–10 (arguing that demand is growing more slowly than in previous periods).

growth due to data centers, electrification, and industrial growth are driving Long-Term Transmission Needs.³⁰² Similarly, state laws, utility integrated resource plans and resource procurements, and other regulatory actions necessarily affect Long-Term Transmission Needs for Commission-jurisdictional transmission services.³⁰³ Several commenters also support the broader consideration of anticipated generation retirements and interconnection requests in regional transmission planning processes because those factors shape the future resource mix and, therefore, Long-Term Transmission Needs.³⁰⁴ Relatedly, many commenters highlight the impact of utility goals on the resource mix because such goals will impact transmission needs.³⁰⁵ Yet, as described above, existing regional transmission planning processes frequently undervalue or entirely omit consideration of some or all of these factors. And while some existing regional transmission planning

³⁰² See, e.g., Northwest and Intermountain Initial Comments at 5 n.12 (“For example, Bonneville Power Administration (‘BPA’) owns about 75 percent of the transmission lines in the Pacific Northwest. In BPA’s 2022 Transmission Service Expansion Plan cluster study, customers submitted 153 separate transmission service requests totaling 11,831 MW of transmission capacity. BPA was able to offer service (without requiring detailed studies and transmission upgrades) to only 275 MWs of those service requests.” (citing BPA, *TSR Study and Expansion Process*, at 12 (Dec. 7, 2021), <https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2021-22tsep-overview.pdf>)); John Wilson and Zach Zimmerman, *The Era of Flat Demand is Over*, Grid Strategies, at 3, 6 (Dec. 2023), <https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf> (noting the 5-year load growth forecast has nearly doubled from 2.6% to 4.7% and “transmission investments need to increase just to keep up with demand”).

³⁰³ See, e.g., Acadia Center and CLF Initial Comments at 8 (“State laws are . . . essential considerations in planning transmission . . . as state laws drive substantial procurements of energy resources along with the concomitant need for additional transmission, as well as repurposed transmission and non-transmission grid solutions.”); AEE Initial Comments at 10 (noting that “[a]s of September 2020, 38 states and the District of Columbia had adopted renewable portfolio standards, and 21 states (plus the District of Columbia and Puerto Rico)—representing more than half of the U.S. population—include a target of 100% renewable energy by 2050 or sooner. Many of these requirements have been enacted in statute and are binding on utilities and retail energy providers.”).

³⁰⁴ See, e.g., Pattern Energy Initial Comments at 26 (“[T]he generation interconnection queues are indicative of the market and should also be a major source for generation assumptions in scenario planning (both near-term and long-term).”); SEIA Initial Comments at 9.

³⁰⁵ See, e.g., Renewable Northwest Initial Comments at 6; SREA Initial Comments at 41–46 (“The major utility announcements of achieving net zero or some approximation affects the marketplace, especially in the [S]outheast.”).

processes do a better job than others of incorporating different components of long-term, forward-looking, and more comprehensive regional transmission planning, the Commission’s existing regional transmission planning requirements do not ensure that factors influencing future transmission will be sufficiently accounted for in that planning.

121. The failure to adequately consider such factors delays planning for the transmission system’s changing operational needs until shortly before those transmission needs manifest. As a result, existing transmission planning processes are piecemeal and fail to take advantage of economies of scale in transmission investment or opportunities to address multiple transmission needs over multiple time horizons.³⁰⁶ We find that engaging in regional transmission planning without adequate consideration of such factors leads to transmission investment that is not more efficient or cost-effective and renders Commission-jurisdictional regional transmission planning and cost allocation processes unjust and unreasonable.³⁰⁷

122. Third, the record demonstrates that the Commission’s regional transmission planning and cost allocation requirements fail to require transmission providers to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs.³⁰⁸ For example, commenters note that many regional transmission planning processes focus too narrowly only on some benefits.³⁰⁹ For instance,

³⁰⁶ PIOs Initial Comments at 10–11; Renewable Northwest Initial Comments at 8 (citing Brattle-Grid Strategies Oct. 2021 Report at iii, iv).

³⁰⁷ See, e.g., AEE Initial Comments at 10 (“Failing to take any of [the Commission-proposed factors] into consideration in developing long-term scenarios would risk under investment in needed regional transmission projects to meet transmission needs and potential[ly] result in unjust and unreasonable rates for transmission service.”); New Jersey Commission Initial Comments at 3–9 (arguing that “[e]nsuring just and reasonable rates requires mandating long-term, multi-value, and portfolio based transmission planning.”).

³⁰⁸ See Order No. 1000, 136 FERC ¶ 61,051 at P 624 (declining to prescribe “a particular definition of ‘benefits’”).

³⁰⁹ Massachusetts Attorney General ANOPR Initial Comments at 22 (“New England’s siloed approach to transmission planning inhibits identification of multi-value solutions.”) As part of ISO-NE’s Boston 2028 Request for Proposals, “[i]n focusing on cost-effectively solving reliability needs alone, ISO-NE rejected all but one of thirty-six proposals. While ISO-NE rejected some of these proposals for technical reasons, it eliminated several due to cost considerations alone.”); PIOs Initial Comments at 10 (“[T]he vast majority of current transmission projects are focused solely either on network reliability or connecting the next

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the Brattle-Grid Strategies Report concludes that “most of [the Nation’s recent transmission] investment addresses individual local asset replacement needs, near-term reliability compliance, and generation-interconnection-related reliability needs without considering a comprehensive set of multiple regional needs and system-wide benefits.”³¹⁰ As PIOs argue, the Commission’s existing regional transmission planning and cost allocation requirements do not require that transmission providers assess “opportunities to benefit from economies of scale that come from ‘right-sizing’ and strategic, comprehensive planning of transmission portfolios and projects to capture additional benefits”³¹¹ Other regional transmission planning processes fail entirely to consider cost savings associated with certain transmission facilities.³¹²

123. Based on the record, we find that, as with the universe of known and measurable factors driving transmission needs, the benefits that regional transmission facilities provide extend beyond those benefits that transmission providers currently consider as part of their regional transmission planning and cost allocation processes.³¹³ Failing to adequately identify and consider the benefits of such transmission facilities may lead to relatively inefficient or less cost-effective transmission

generator in the interconnection queue and ignore any other potential benefits, possible economies of scale or other efficiencies that might occur by considering multiple future needs [M]ultiple quantifiable benefits to transmission . . . are being ignored in the transmission planning process.”).

³¹⁰ Brattle-Grid Strategies Oct. 2021 Report at 2.

³¹¹ PIOs Initial Comments at 10–11. The benefits cited by PIOs “include congestion relief, reduced transmission losses, resiliency to extreme weather events, increased flexibility to respond to changing market or system conditions, and facilitating larger regional or interregional solutions for cost effective interconnection of the renewable and storage resources needed to meet public policy goals.” *Id.* at 11.

³¹² SREA Initial Comments at 24 (“SERTP participants explained that SERTP is unable to conduct adjusted production cost savings, because none of the utilities involved in SERTP have the software capable of doing so. In effect, the ‘Economic Planning Studies’ only evaluate the costs of potential upgrades to the system, but none of the benefits.”).

³¹³ We disagree with Potomac Economics’ arguments that the sole benefit of transmission is alleviating congestion and that congestion is primarily an economic issue, so investment in alleviating congestion should not exceed the benefit of doing so. See Potomac Economics Initial Comments at 3–4. As discussed *infra* in the Evaluation of the Benefits of Regional Transmission Facilities section alleviating congestion is just one of many potential benefits that transmission infrastructure provides, and transmission benefits beyond solving congestion are considered by transmission providers in regional transmission planning processes today.

development. In particular, the cost-benefit analyses that transmission providers often use as part of the evaluation process may fail to identify more efficient or cost-effective regional transmission facilities for selection because they provide an inaccurate portrayal of the comparative benefits of different transmission facilities. Thus, the failure to adequately consider the benefits of regional transmission facilities results in, among other things, transmission customers forgoing benefits that may significantly outweigh their costs, which results in less efficient or cost-effective transmission investments and, in turn, contributes to Commission-jurisdictional rates that are unjust and unreasonable.

124. Given our findings above concerning the deficiencies in existing transmission planning requirements, and our conclusion that long-term, forward-looking, and more comprehensive regional transmission planning is needed, we also conclude that existing cost allocation requirements are deficient and must be modified to properly account for Long-Term Regional Transmission Planning. The Commission has long recognized the “close relationship between transmission planning, which identifies needed transmission facilities, and the allocation of costs of the transmission facilities in the plan,”³¹⁴ and that cost allocation issues will often determine whether transmission providers and customers support the construction of new facilities.³¹⁵ Furthermore, experience with Order No. 1000 has reinforced the critical role that states play in the development of new transmission infrastructure, particularly at the regional level, where transmission projects may physically span, and their costs may be allocated across, multiple states. As the Commission discussed in the NOPR and we continue to find in this final order, facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.³¹⁶

125. Given the link between cost allocation and transmission planning, it is essential that cost allocation requirements for Long-Term Regional Transmission Facilities are appropriately tailored to the new Long-Term Regional Transmission Planning requirements of this order, particularly

given the anticipated long-lead time for any regional transmission facilities developed and regionally cost allocated through this final order. Without proper alignment of the regional transmission planning and cost allocation requirements, it is less likely that transmission facilities selected in Long-Term Regional Transmission Planning will be developed, which would undermine the essential purpose of the regional transmission planning process, namely, the development of more efficient or cost-effective regional transmission facilities.

126. We find that the Commission’s current cost allocation requirements, which were designed and established in the context of existing Order No. 1000 regional transmission planning processes, are insufficient to appropriately allocate costs associated with regional transmission facilities that are selected in accordance with the new Long-Term Regional Transmission Planning requirements that we establish in this final order. The Commission’s existing Order No. 1000 cost allocation requirements contemplate the application of differing cost allocation methods to different types of transmission facilities. But we find that Long-Term Regional Transmission Planning, which accounts for multiple drivers of Long-Term Transmission Needs and results in Long-Term Regional Transmission Facilities that produce a broader set of benefits, warrants a different approach to cost allocation for such transmission facilities. Likewise, existing Order No. 1000 regional transmission planning processes do not mandate the consideration of specific benefits that we believe are appropriately considered as part of Long-Term Regional Transmission Planning. New information concerning these benefits uncovered through the transmission planning process may be relevant when allocating the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with their benefits.³¹⁷ Importantly, existing cost allocation requirements do not provide a dedicated process through which states have an opportunity to participate in the development of regional cost allocation methods. We conclude such a role is particularly relevant to Long-Term Regional Transmission Planning, given: (1) the lengthy planning horizon over

³¹⁴ Order No. 1000, 136 FERC ¶ 61,051 at P 496.

³¹⁵ Order No. 890, 118 FERC ¶ 61,119 at P 557; see also Order No. 1000, 136 FERC ¶ 61,051 at P 496.

³¹⁶ NOPR, 179 FERC ¶ 61,028 at P 301; *infra* Regional Transmission Cost Allocation section.

³¹⁷ *Ill. Commerce Comm’n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) (*ICC v. FERC I*); Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639 (requiring costs of regional transmission facilities to be allocated in a manner that is at least roughly commensurate with estimated benefits).

which transmission projects might be identified, selected, and ultimately constructed; (2) the resultant increased uncertainty for Long-Term Regional Transmission Facilities; and (3) accordingly, the increased importance for state engagement regarding cost allocation to increase the likelihood such facilities obtain needed siting approvals from the states and are thus timely and cost-effectively developed. We therefore believe that it is both necessary and appropriate to establish specific cost allocation requirements that are tailored to the Long-Term Regional Transmission Planning reforms in this final order.

127. Based on the record, including comments submitted in response to the NOPR, we find that there is substantial evidence demonstrating that Long-Term Regional Transmission Planning and cost allocation to identify and plan for Long-Term Transmission Needs does not occur on a consistent and sufficient basis.³¹⁸ We find, in large part, that this is because of the deficiencies that we have identified above in the Commission's existing regional transmission planning and cost allocation requirements. In addition, we find that, in the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes, transmission providers are meeting many transmission needs by identifying transmission solutions and developing transmission facilities through other processes, *i.e.*, outside of the regional transmission planning and cost

allocation processes,³¹⁹ or, as discussed above, in response to near-term reliability needs,³²⁰ which may not identify the more-efficient or cost-effective solution.

128. To reiterate, the fact that transmission facilities are being identified and built outside of regional transmission planning processes and in response to near-term reliability needs is not inherently problematic. In many instances, as some commenters point out,³²¹ those processes may be well equipped to identify necessary and appropriate transmission solutions. Rather, the problem is that incremental and piecemeal expansion of the transmission system outside of regional transmission planning process misses the potential for transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to solve Long-Term Transmission Needs, as well as to afford system-wide benefits that may not be achieved through one-off transmission system upgrades.³²² To the extent that transmission providers may not be identifying and evaluating the more efficient or cost-effective transmission solutions needed to meet underlying transmission needs, including Long-Term Transmission Needs, over time, consumers will bear the costs of relatively inefficient or less cost-effective piecemeal transmission investment and expansion.³²³

³¹⁸ See New Jersey Commission Initial Comments at 8 (explaining that, outside of limited circumstances, PJM, Florida, ISO-NE, Southeastern Regional, South Carolina Regional, WestConnect, NorthernGrid, NYISO, SPP, and CAISO do not conduct multi-driver or portfolio transmission planning, which has required ratepayers to pay for tens of billions of dollars in unnecessary transmission projects); NextEra ANOPR Initial Comments at 71 ("While there are examples of longer-term planning currently being utilized by some regions, such as MISO's annual 15-year Futures assessment or SPP's 20-year Integrated Transmission Plan run every five years, there is no standard as to what time horizon long-term planning must study, nor how often this planning should be done. Further, no standards or guidelines exist as to what should be included in such long-term planning to ensure that customers are charged just and reasonable rates for the most efficient and cost-effective investments given the most comprehensive and up-to-date information available."); Western PIOs Initial Comments at 4–28 (arguing that in the Western United States transmission planning outside of CAISO is not developed and is ineffective); Brattle-Grid Strategies Oct. 2021 Report at 13–15 & tbl. 2 (documenting inconsistent "use of proactive, scenario-based, multi-value processes" across various planning authorities, including NYISO, CAISO, MISO, PJM, ISO-NE, Florida, Southeast Regional, and South Carolina").

³¹⁹ See, e.g., LS Power Initial Comments at 46–50; PIOs Initial Comments at 9–10 (explaining that about half of the approximately \$70 billion in aggregate transmission investment by Commission-jurisdictional transmission owners in RTO/ISO regions was approved outside of regional transmission planning processes).

³²⁰ *Supra* note 309.

³²¹ E.g., Duke Initial Comments at 7.

³²² See, e.g., ACORE Initial Comments at 8 ("For example, two solutions to address a particular reliability need may offer vastly different total system-wide benefits. Thus, the higher-cost transmission solutions can actually result in significantly lower net cost from a system-wide perspective.") (quoting Brattle-Grid Strategies Oct. 2021 Report at 30); Clean Energy States Initial Comments at 2 ("[T]he one-plant-at-a-time approach to transmission upgrades results in a patchwork approach that drives up costs and misses opportunities for improvements to the system as a whole."); Exelon Initial Comments at 5.

³²³ Michigan State Entities Initial Comments at 1–2 (explaining concerns that the lack of long-term transmission planning has led to significantly higher residential rates and how the problem will worsen if transmission investment does not reflect changes in the resource mix and demand); New Jersey Commission Initial Comments at 6–7 (noting PJM analysis showing transmission upgrades to interconnect 87.1 GW of a variety of resources, including offshore wind, would cost \$3.2 billion if done through holistic transmission planning whereas connecting only 15.4 GW of offshore wind would cost \$6.4 billion if done through the interconnection queue process, and estimating that the interconnection of 87.1 GW through the interconnection queue would increase the cost to

129. We find that the concerns arising from the absence of sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes and the corresponding failure by transmission providers to identify and evaluate more efficient or cost-effective transmission solutions to Long-Term Transmission Needs are exacerbated by the fact that transmission needs in most transmission planning regions are drastically changing. Contrary to the claims of some commenters, we are not promulgating this order in an attempt to steer the resource mix and demand³²⁴ based on a preference for certain resources over others.³²⁵ Instead, the Commission is reacting to well-documented factors, which the record demonstrates are driven by exogenous forces beyond the Commission's jurisdiction or control, including, but not limited to, the increasing frequency of extreme weather events, customer preferences, demand growth, economic and technological trends, and Federal, federally-recognized Tribal, state, and local policies.³²⁶

consumers by over \$30 billion compared to holistic transmission planning); PIOs Initial Comments at 8 (noting how deficiencies in the Commission's regional transmission planning processes have "led to billions of dollars in excessive costs for consumers." (citing Brattle-Grid Strategies Oct. 2021 Report at 1–13 (Section 1))).

³²⁴ Consumer Organizations Initial Comments at 1–2; ELCON Initial Comments at 9; SERTP Sponsors Initial Comments at 16–20. *But see* SEIA Reply Comments at 2–3 ("The NOPR does make 'repeated references' to the changing resource mix. But that is not because the NOPR will 'promote a transition to a more renewables-heavy electric system.' The NOPR makes these references because the resource mix is, in fact, changing. The question before the Commission is not whether to promote or impede that change, but how to address the needs of the grid as a result of that inevitable change." (internal quotations omitted)); New Jersey Commission Reply Comments at 2 ("The Commission is . . . trying to ensure the electricity system can reliably and efficiently achieve the generation mix that state policymakers and voluntary consumers—not the Commission—have chosen. Ensuring that these customers are served at the lowest possible cost while maintaining reliability is entirely consistent with and indeed required in order to meet the dictates of the FPA. In other words, the Commission is acting to ensure transmission planning processes account for current realities and meet evolving consumer needs at a total cost that is just and reasonable." (internal citations omitted)).

³²⁵ See, e.g., Ohio Commission Federal Advocate Initial Comments at 4–6 (arguing that the Commission's purpose in issuing the NOPR was to promote an aspirational renewable future and achieve narrow environmental objectives); Undersigned States Reply Comments at 7 (arguing that the Commission is forcing ratepayers to subsidize forms of energy by socializing the cost of a transmission build out).

³²⁶ See New Jersey Commission Initial Comments at 3 ("The Commission is not proposing to unduly favor, mandate, or subsidize forms of generation but is rather seeking to ensure that the bulk electricity

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130. In response to commenters, we acknowledge that integrated resource planning processes, where they exist, shape the resource mix and can often include forms of proactive transmission planning. As stated in Order No. 1000, we reiterate that “the regional transmission planning process is not the vehicle by which integrated resource planning is conducted.”³²⁷ Indeed, this final order does not aim to affect—either facilitate or hinder—any changes or decisions that occur outside of the Commission’s jurisdiction. Instead, because practices directly affecting Commission-jurisdictional rates, terms, and conditions of service for interstate transmission and wholesale electricity are the exclusive jurisdiction of the Commission, we must ensure that Commission-jurisdictional processes associated with regional transmission planning and cost allocation result in rates that are just and reasonable and not unduly discriminatory or preferential. To this end, this final order is focused on ensuring that regional transmission planning processes are adequately *accounting* for the changes occurring outside of the Commission’s jurisdiction, including the resource decisions that are the exclusive jurisdiction of states.³²⁸ Additionally, to the extent that integrated resource planning processes include forms of transmission planning, such planning can be complementary to Commission-jurisdictional regional transmission planning processes but cannot take the place of such processes. This is not to diminish the importance of integrated resource planning processes, which serve a critical role in shaping the generation mix and transmission infrastructure. In recognition of this role, this final order requires transmission providers to consider integrated resource planning as a factor when conducting Long-Term Regional Transmission Planning. But, as discussed below, we conclude that integrated resource planning is appropriately considered as *one of several* categories of factors used to develop Long-Term Scenarios and

system maintains reliability and satisfies evolving consumer demand . . .”).

³²⁷ Order No. 1000, 136 FERC ¶ 61,051 at P 154.

³²⁸ See *PJM Power Providers Grp. v. FERC*, 88 F.4th 250, 275 (3d Cir. 2023) (holding that the Commission is “unambiguously authorize[d] . . . to take state policies into account to the extent that such policies affect [the Commission’s] statutorily prescribed area of focus . . .”); see also *Elec. Power Supply Ass’n v. Star*, 904 F.3d 518, 524 (7th Cir. 2018) (approving of the Commission’s decision to take state zero-emissions credit systems like that in Illinois “as givens and set out to make the best of the situation [these systems] produce”).

identify Long-Term Transmission Needs.

131. In response to commenters that argue regional transmission facilities may not address local transmission needs such that a local transmission facility would still be needed,³²⁹ we acknowledge that regional transmission facilities are not necessarily always a more efficient or cost-effective solution to address local transmission needs, and nothing in this final order requires transmission providers to rely on regional transmission facilities to address exclusively local transmission needs. Instead, this final order identifies deficiencies in existing Commission-jurisdictional regional transmission planning processes that lead transmission providers to fail to identify Long-Term Transmission Needs and fail to identify, evaluate, or select more efficient or cost-effective transmission solutions to meet those transmission needs. As a result of these deficiencies, transmission providers may undertake relatively inefficient investments in transmission infrastructure by missing opportunities to identify regional transmission facilities that bring economies of scale or address multiple transmission needs over different time horizons, including local transmission needs.

132. We disagree with arguments that the Commission cannot promulgate this final order because we rely on general findings, rather than individualized analyses of each, specific transmission planning region.³³⁰ Relevant precedent, including regarding the Commission’s comparable action in Order No. 1000, is clear that the Commission has discretion as to the procedural means through which it will apply its substantive expertise, and we need not make findings that are region specific in every case; rather, we are empowered to “rely on ‘generic’ or ‘general’ findings of a systemic problem to support imposition of an industry-wide solution,”³³¹ and we do so here. The fact that individual transmission planning regions may have different forms of transmission planning processes, and may experience varying levels of transmission investment, would be “as unastonishing as it is

³²⁹ See, e.g., Duke Initial Comments at 9 (arguing that there are instances in which larger regional transmission projects may not resolve localized transmission needs).

³³⁰ See, e.g., Louisiana Commission Reply Comments at 5–6; NRECA Initial Comments at 14–16.

³³¹ *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67 (quoting *Interstate Nat. Gas v. FERC*, 285 F.3d 18, 37 (D.C. Cir. 2002)).

irrelevant.”³³² Moreover, although transmission planning practices vary considerably between transmission planning regions and some regions may engage in transmission planning that shares many of the elements of the more long-term, forward-looking, comprehensive regional transmission planning required in this order, the record demonstrates that this final order identifies deficiencies that reach well beyond “isolated pockets[.]”³³³ Rather, the record demonstrates that these deficiencies pervade large swaths of the country, which include RTO/ISO and non-RTO/ISO transmission planning regions.³³⁴ Accordingly, this final order’s remedy does not present an “extreme ‘disproportion of remedy to ailment[.]’”³³⁵ The Commission may reasonably rely on a rulemaking procedure to address the industry-wide changes to the transmission landscape, notwithstanding regional variation among regional transmission planning processes. As the Commission stated in Order No. 1000, “[i]t is well established that the choice between rulemaking and case-by-case adjudication ‘lies primarily in the informed discretion of the administrative agency.’”³³⁶ The Commission also stated that “[i]t is within our discretion to conclude that a generic rulemaking, not case-by-case adjudications, is the most efficient approach to take to resolve the industry wide problems facing us.”³³⁷ Moreover, we agree with ACEG that pursuing region-specific solutions will lead to “siloed and disjunctive transmission planning policies [that] will not solve the problems facing the nation’s electric grid.”³³⁸

133. Furthermore, although not every transmission planning region is experiencing these changes in equal measure, the record shows that significant changes are well underway nationwide, and that failing to adequately account for Long-Term Transmission Needs poses a risk to just and reasonable rates throughout the country.³³⁹ In fact, the record raises a wide range of concerns, and the Commission need not, and should not, wait for systemic problems to undermine regional transmission

³³² *Id.* (quoting *Wis. Gas v. FERC*, 770 F.2d 1144, 1157 (D.C. Cir. 1985)).

³³³ *Id.*

³³⁴ See, e.g., *supra* notes 283 and 284 (explaining that ISO-NE, SERTP, Northern Grid, and PJM undergo transmission planning using time horizons shorter than 20 years).

³³⁵ *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 67.

³³⁶ Order No. 1000, 136 FERC ¶ 61,051 at P 60.

³³⁷ *Id.*

³³⁸ ACEG Reply Comments at 17.

³³⁹ AEE Reply Comments at 3–4.

planning in every region before it acts.³⁴⁰ The record in this proceeding confirms that significant investments in new transmission facilities are expected to occur, with substantial impacts on the Commission-jurisdictional rates that customers pay.³⁴¹ It is therefore critical, and it is the Commission's responsibility, to act now to address deficiencies in its regional transmission planning and cost allocation requirements to ensure that more efficient or cost-effective transmission investments are made as the industry addresses the changing landscape.³⁴²

3. Benefits of Long-Term Regional Transmission Planning and Cost Allocation To Identify and Plan for Long-Term Transmission Needs

134. Upon consideration of the record, we find that the requirements set forth in this final order will address deficiencies in the existing regional transmission planning and cost allocation requirements and will promote enhanced reliability and more efficient or cost-effective transmission solutions, which will help to ensure just and reasonable Commission-jurisdictional rates.

135. The record demonstrates that long-term, forward-looking, and more comprehensive regional transmission planning that identifies Long-Term Transmission Needs will help transmission providers to identify, evaluate, and select more efficient or cost-effective transmission solutions to those needs. For example, like the Commission in the NOPR,³⁴³ commenters cite to the success of MISO's Long-Range Transmission Plan in delivering more efficient or cost-effective transmission solutions. By addressing public policy, economic, and reliability transmission planning needs simultaneously through its MVP category, MISO "eliminate[d] the need for \$300 million in future baseline reliability upgrades," and provided production cost savings that *exceeded the entire cost of the portfolio by \$10 billion.*³⁴⁴ Brattle Group and Grid Strategies also found that "building out piecemeal network upgrades through the interconnection queue process to integrate the same amount of generation would have cost over 80% more than

the cost of the MVP portfolio."³⁴⁵ Similarly, the New Jersey Commission asserts that, by planning transmission facilities to address a specific set of known and identified transmission needs through a holistic portfolio, rather than piecemeal through the generator interconnection process, PJM could save customers more than \$30 billion.³⁴⁶

136. We note that the cost-saving results that MISO experienced were the direct product of more comprehensive, longer-term regional transmission planning. By expanding the transmission planning horizon and considering factors affecting Long-Term Transmission Needs, as well as considering a broader list of benefits, transmission providers will be able to identify, evaluate, and select more efficient or cost-effective transmission solutions to address Long-Term Transmission Needs.³⁴⁷ Such Long-Term Regional Transmission Planning will: (1) reduce reliance on transmission solutions that are relatively inefficient or less cost-effective because they address only short-term transmission needs; (2) unlock the benefits of economies of scale in transmission investment;³⁴⁸ (3) enable opportunities to "right size" replacement transmission facilities;³⁴⁹ (4) facilitate the selection of regional transmission facilities that could address multiple transmission needs over different time horizons; and (5) provide states, utilities, customers, and other stakeholders with greater insight and transparency into the costs and benefits of particular transmission solutions to address Long-Term Transmission Needs. We conclude that

these regional transmission planning and cost allocation reforms will benefit customers by leading to more efficient or cost-effective transmission investment, thereby helping to ensure just and reasonable rates.³⁵⁰

137. In addition to potentially enhancing the efficiency and cost-effectiveness of transmission investment, we find that sufficiently long-term, forward-looking, and comprehensive regional transmission planning and cost allocation processes will enhance reliability. In the NOPR, the Commission found that a robust, well-planned transmission system is foundational to ensuring an affordable, reliable supply of electricity. The record supports this conclusion. Many commenters agree that, especially in light of continuing changes in both supply and demand, ongoing investment in regional transmission facilities is necessary to ensure that the transmission system continues to serve load in a reliable manner at reasonable cost.³⁵¹ Commenters also agree that regional transmission investments support enhanced reliability because larger, more integrated transmission systems are better equipped to accommodate a diversity of supply and demand conditions and provide redundancy that allow the system to better withstand unpredictable and extreme weather events, which are

³⁵⁰ See, e.g., Exelon Initial Comments at 5 ("The project-by-project approach of developing [interconnection-related] network upgrades in response to generator interconnection requests does not take into account broader, longer-term planning needs and furthermore raises questions about whether it will lead to efficient and cost-effective outcomes as the resource mix rapidly evolves."); PIOs Initial Comments at 8 ("[O]verwhelming evidence indicates that transmission owners are largely able to evade the requirements of Order No. 1000 and . . . have primarily invested in local projects. This has led to . . . billions of dollars in excessive costs for consumers." (citing Brattle-Grid Strategies Oct. 2021 Report at Section 1)); Southeast PIOs Reply Comments at 2 ("All the while, snowballing inefficiencies created by numerous small-scale transmission band-aids, unfit to address broader generation trends, translate into excessive, unjust, and unreasonable rates borne by an already overburdened populace.").

³⁵¹ ACOE ANOPR Initial Comments at 21–22 (explaining how additional transmission investments can alleviate billions of dollars in costs caused by extreme weather); EEI Initial Comments at 4 ("Transmission plays and will continue to play a vital role in enabling the energy transition and in ensuring a reliable and resilient energy grid. A robust transmission system will not only enable electric utilities to integrate more renewable energy resources and deliver more clean energy to customers but will also enhance the reliability and resiliency of the grid and enable the deployment of new technologies." (citing EEI, *Planning and Developing Electric Transmission Projects: The Path to the Grid of the Future* (2022)); NERC Initial Comments at 6 (explaining that transmission will be key to managing a reliable transformation in the resource mix).

³⁴⁵ *Id.* at 4–5 (citing Brattle-Grid Strategies Oct. 2021 Report at 7 & nn.13–14); see *id.* at 5 n.9 (noting that the cost of the MVP portfolio divided by the amount of wind capacity it interconnected came to \$412 per kilowatt, while interconnection-related network upgrades for new generation in MISO planned through the interconnection queue cost \$756 per kilowatt).

³⁴⁶ *Id.* at 6–7 (citing Brattle-Grid Strategies Oct. 2021 Report at 7); *id.* (explaining that the onshore network upgrades required to interconnect 87.1 GW of resources meeting all of PJM states' current offshore wind goals and total renewable portfolio standards through "piecemeal interconnection queue projects would cost nearly \$36 billion in total—more than eleven times the \$3.2 billion cost of the integrated portfolio approach," or "[p]ut another way, proactive, portfolio-based planning in PJM could ultimately save ratepayers over \$30 billion compared to the status quo.").

³⁴⁷ PIOs Initial Comments at 35.

³⁴⁸ *Id.* at 10 ("[T]he vast majority of current transmission projects are focused solely either on network reliability or connecting the next generator in the interconnection queue and ignore any other potential benefits, possible economies of scale or other efficiencies that might occur by considering multiple future needs.").

³⁴⁹ ACEG Initial Comments at 53–56; Clean Energy Associations Initial Comments at 25–27; SEIA Initial Comments at 25–26.

³⁴⁰ See Order No. 1000, 136 FERC ¶ 61,051 at P 50.

³⁴¹ See *supra* P 93.

³⁴² See Order No. 1000, 136 FERC ¶ 61,051 at P 46.

³⁴³ See, e.g., NOPR, 179 FERC ¶ 61,028 at PP 31–32.

³⁴⁴ New Jersey Commission Initial Comments at 4 (citing MTEP2017 Review at 6, 8) (emphasis in original).

occurring with increased frequency and severity.³⁵²

138. Moreover, commenters provide examples of how long-term, forward-looking, and more comprehensive regional transmission planning can better identify reliability needs and resolve these needs with more efficient or cost-effective transmission solutions.³⁵³ For example, as noted above, MISO's MVP Portfolio 4 eliminated the need for \$300 million in future baseline reliability upgrades.³⁵⁴ By comparison, the Reliability Must-Run Agreement for Indian River Unit 4, a 410 MW coal-fired generation unit, highlights the costs of inadequate regional transmission planning. As NARUC explains, the Indian River Unit 4 was scheduled to retire, but PJM found that retirement would cause reliability issues and would necessitate upgrades to transmission facilities that, due to their age, were already due to be upgraded, and that the Reliability Must-Run Agreement was needed because those upgrades would take five years to complete.³⁵⁵ A long-term, forward-looking, and more comprehensive regional transmission planning process may have obviated the need for the Reliability Must-Run Agreement, the individual transmission facility upgrades, or both.

4. Conclusion

139. In consideration of the record provided in this proceeding, as well as the related conclusions stated above, we find that the Commission's existing regional transmission planning and cost allocation requirements are unjust, unreasonable, and unduly discriminatory or preferential because they fail to require transmission providers to adequately plan on a sufficiently long-term, forward-looking,

and comprehensive basis. Specifically, as discussed, we find that the Commission's regional transmission planning and cost allocation requirements fail to require transmission providers to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We find that reforms to those requirements are thus necessary to ensure that Commission-jurisdictional rates are just, reasonable, and not unduly discriminatory or preferential. The failure to plan on a sufficiently long-term, forward-looking, and comprehensive basis results in the potential for relatively inefficient or less cost-effective transmission development for which customers must pay. The requirements set forth in this final order will help to ensure that transmission providers plan to address Long-Term Transmission Needs, in turn helping to ensure more efficient or cost-effective transmission development and thus just and reasonable Commission-jurisdictional rates.

III. Long-Term Regional Transmission Planning

A. Requirement To Participate in Long-Term Regional Transmission Planning

1. NOPR Proposal

140. In the NOPR, the Commission proposed to require each transmission provider to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning,³⁵⁶ meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify transmission needs driven by changes in the resource mix and demand and to identify and evaluate transmission facilities for potential selection as the more efficient or cost-effective transmission facilities to meet such needs.³⁵⁷

141. The Commission proposed that transmission providers may continue to

rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.³⁵⁸

142. The Commission proposed that transmission providers that comply with the Long-Term Regional Transmission Planning requirements will comply with the requirement in Order No. 1000 that they participate in a regional transmission planning process that considers, and has associated cost allocation provisions related to, transmission needs driven by Public Policy Requirements.³⁵⁹ The Commission further proposed to allow transmission providers to propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes they use to consider transmission needs driven by Public Policy Requirements.³⁶⁰ The Commission stated, however, that such continued use of existing regional transmission planning and cost allocation processes would not supplant transmission providers' obligations to comply with the Long-Term Regional Transmission Planning requirements established in any final order in this proceeding. Moreover, the Commission proposed that transmission providers seeking to retain existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements would have to demonstrate that continued use of any such processes does not interfere or otherwise undermine the Long-Term Regional Transmission Planning proposed in the NOPR by demonstrating that continued use of such processes is consistent with or superior to any final order issued in this proceeding.³⁶¹

143. The Commission preliminarily found that transmission providers could propose a regional transmission planning process that plans for reliability needs, economic needs, transmission needs driven by Public Policy Requirements, and transmission needs driven by changes in the resource mix and demand simultaneously through a combined approach. The Commission stated that transmission providers proposing to address all such transmission needs in a single regional transmission planning process would bear the burden of demonstrating continued compliance with Order No.

³⁵² NERC Initial Comments at 6 (explaining that regional transmission planning is necessary to ensure sufficient transmission capacity to move energy from areas with a surplus to areas that are deficient).

³⁵³ ITC Initial Comments at 44 ("While local transmission planning continues to serve a critically necessary, valuable function in maintaining the reliability and efficiency of transmission systems, it is nonetheless clear that holistic, long range transmission planning is far more capable of identifying optimal transmission solutions that serve the most needs and deliver the most benefits."); MISO Initial Comments at 88 (explaining that in its Tranche 1 Long Range Transmission Plan, MISO recognizes Avoided Transmission Investment benefits provided by Long Range Transmission Plan facilities in addressing both avoided reliability projects and avoided age and condition replacement projects with the results being avoided costs in local transmission that would have otherwise been incurred to replace existing facilities).

³⁵⁴ New Jersey Commission Initial Comments at 4.

³⁵⁵ NARUC Initial Comments at 14–15.

³⁵⁶ The two features of Long-Term Regional Transmission Planning that the Commission included in the proposed reforms were the development of scenarios with a 20-year transmission planning horizon to be reassessed and revised every three years, with each such reassessment providing the basis for identification and evaluation of transmission facilities for potential selection. NOPR, 179 FERC ¶ 61,028 at P 68 n.128.

³⁵⁷ See *id.* PP 54, 64, 68.

³⁵⁸ *Id.* P 72.

³⁵⁹ *Id.* P 73.

³⁶⁰ *Id.* P 74.

³⁶¹ *Id.*

1000 in addition to compliance with the requirements of any final order in this proceeding.³⁶²

144. Finally, the Commission proposed to require that Long-Term Regional Transmission Planning comply with the following existing Order Nos. 890 and 1000 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; and (6) dispute resolution.³⁶³

2. Comments

a. General Comments

145. The majority of commenters support the Commission's proposal.³⁶⁴

³⁶² *Id.* P. 75.

³⁶³ *Id.* P. 76.

³⁶⁴ Acadia Center and CLF Initial Comments at 2; ACEG Initial Comments at 6, 22–23; ACORE Initial Comments at 2, 17; Advanced Energy Buyers Initial Comments at 4; AEP Initial Comments at 5–7; Amazon Initial Comments at 2; BP Initial Comments at 4–7; Breakthrough Energy Initial Comments at 3; Breakthrough Energy Supplemental Comments at 1; Business Council for Sustainable Energy Initial Comments at 2–4; California Energy Commission Initial Comments at 1; City of New Orleans Council Initial Comments at 4; City of New York Initial Comments at 1, 3; Clean Energy Associations Initial Comments at 10; Conservative Energy Network Supplemental Comments at 1; Conservatives for Clean Energy—Florida Supplemental Comments at 1; Conservatives for Clean Energy—South Carolina; CTC Global Initial Comments at 1; US Senators Supplemental Comments at 1–2; EEI Initial Comments at 10; ELCON Initial Comments at 6–7; NERC Initial Comments at 6–7; ENGIE Initial Comments at 2; Entergy Initial Comments at 7; Environmental Groups Supplement Comments at 2; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 2; Exelon Initial Comments at 4–7; Form Energy Initial Comments at 2–3; Governor of Kansas Laura Kelly Supplemental Comments at 1; Handy Law Initial Comments at 7–8; US House Republicans Supplemental Comments at 1; Indicated PJM TOs Initial Comments at 7–8; Indicated US Senators and Representatives Initial Comments at 1; Michigan Conservative Energy Forum Supplemental Comments at 1; ISO–NE Initial Comments at 2, 8; ITC Initial Comments at 5–9; Joint Consumer Advocates Initial Comments at 5–6; Minnesota State Entities Initial Comments at 4; NARUC Initial Comments at 4; National Grid Initial Comments at 9–11; NEMA Initial Comments at 1–2; NESCOE Initial Comments at 14–16; New England for Offshore Wind Initial Comments at 2; New York Commission and NYSEDA Initial Comments at 8; New York TOs Initial Comments at 1; New York Transco Initial Comments at 1; NextEra Initial Comments at 62; Northwest and Intermountain Initial Comments at 7; Ohio Conservative Energy Forum Supplemental Comments at 1; Pine Gate Initial Comments at 18–19; PIOs Initial Comments at 12–14; Policy Integrity Initial Comments at 5; RMI Supplemental Comments at 2; Senator Schumer Supplemental Comments at 1–2; Senator Whitehouse Supplemental Comments at 1–3; SDG&E Initial Comments at 2; Southeast PIOs Initial Comments at 42–49; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments); US Climate Alliance Initial Comments at 1–2; Vermont Electric and Vermont Transco Initial Comments at 3; Virginia Commission Staff Initial Comments at 2–3; Western PIOs Initial Comments at 28–30, 36;

with multiple commenters claiming that Long-Term Regional Transmission Planning is crucial to ensure that regional transmission planning appropriately identifies transmission needs to meet the changing resource mix and demand.³⁶⁵

146. AEP and Ørsted argue that the Commission's proposal will address deficiencies in the current transmission planning process.³⁶⁶ National Grid claims that existing long-term transmission planning processes are sufficient for addressing reliability and economic transmission needs in the near-term but are inadequate for addressing the changing resource mix and demand, as well as for addressing resilience challenges driven by climate change.³⁶⁷ ACEG claims that Long-Term Regional Transmission Planning will allow right-sizing of transmission facilities.³⁶⁸

147. Some commenters observe that this proposal may result in cost-savings for consumers. For example, DC and MD Offices of People's Counsel claim that this proposal could result in significant cost savings to consumers by helping address severe weather events and reduce the relative cost of decarbonizing the country's resource fleet.³⁶⁹ AEP argues that the NOPR proposal will benefit consumers by establishing a process that will identify more efficient or cost-effective transmission facilities, capturing currently missed opportunities and achieving economies of scale.³⁷⁰ North Carolina Commission and Staff argue that Long-Term Regional Transmission Planning can provide state utility commissions and consumer advocates with useful information to promote a cost-effective and reliable transmission grid.³⁷¹

Western Way Colorado Supplemental Comments at 1; Western Way Nevada Supplemental Comments at 1; Western Way Utah Supplemental Comments at 1; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

³⁶⁵ Breakthrough Energy Initial Comments at 12; EEI Supplemental Comments at 1; Exelon Initial Comments at 5; US House Republicans Supplemental Comments at 1; ITC Initial Comments at 5.

³⁶⁶ AEP Initial Comments at 8; Ørsted Initial Comments at 4–5.

³⁶⁷ National Grid Initial Comments at 10.

³⁶⁸ ACEG Initial Comments at 6.

³⁶⁹ DC and MD Offices of People's Counsel Initial Comments at 8–10 (citing Patrick Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 *Joule* 115, 115–134 (2020), https://www.sciencedirect.com/science/article/pii/S2542435120305572?dgcid=author%20_blank); see also EEI Supplemental Comments at 1 (arguing that robust transmission development will provide cost savings from greater access to low-cost resources).

³⁷⁰ See AEP Initial Comments at 8–12.

³⁷¹ North Carolina Commission and Staff Initial Comments at 4.

148. NextEra states that Long-Term Regional Transmission Planning can minimize overall costs to consumers by enabling the lowest-cost generation.³⁷² Relatedly, Tabors Caramanis Rudkevich states that the NOPR proposal would establish a transmission planning process that coordinates across franchises, states, and regions, which will reduce the production cost of delivery of energy to consumers.³⁷³

149. PPL notes that Long-Term Regional Transmission Planning may improve some of the limitations of criteria-based transmission planning, which is currently employed in RTOs/ISOs.³⁷⁴ Ørsted supports the proposed requirements regarding Long-Term Regional Transmission Planning and argues that existing regional transmission plans fail to anticipate the size and scale of future offshore wind generation development, leading to inaccurate plans and insufficient investment in infrastructure needed to integrate known future offshore wind generation.³⁷⁵

150. State Agencies assert that the Commission's various proposed reforms in the NOPR collectively would enhance transparency, prevent unnecessary investment in local transmission projects, and improve the competitive landscape.³⁷⁶ US DOJ and FTC support reforms that address obstacles to transmission development and that are implemented consistent with principles for competition.³⁷⁷

b. Requests for Flexibility in Transmission Planning

151. A number of commenters support the Commission's proposal to require Long-Term Regional Transmission Planning, but also express reservations or objections regarding what they perceive as an overly prescriptive approach that may disrupt existing processes that are already working.³⁷⁸ For example, multiple

³⁷² NextEra Initial Comments at 62.

³⁷³ Tabors Caramanis Rudkevich Initial Comments at 4–5.

³⁷⁴ PPL Initial Comments at 4. PPL claims that, while PJM may perform long-term transmission planning on a 15-year time frame on paper, its long-term transmission planning is effectively undertaken over only 7 to 10 years. *Id.*

³⁷⁵ Ørsted Initial Comments at 4–5.

³⁷⁶ State Agencies Reply Comments at 6.

³⁷⁷ US DOJ and FTC Initial Comments at 19.

³⁷⁸ See, e.g., Avangrid Initial Comments at 6, 9; CAISO Initial Comments at 1–2, 7–10, 13; California Commission Initial Comments at 6; Duke Initial Comments at 1–2; Indiana Commission Initial Comments at 1, 3; ISO–NE Initial Comments at 20; ISO/RTO Council Initial Comments at 4–5 (citing NOPR, 179 FERC ¶ 61,028 at PP 66, 104); Massachusetts Attorney General Initial Comments at 10–12; Michigan Commission Initial Comments

commenters express concerns that the NOPR's allegedly prescriptive requirements for Long-Term Regional Transmission Planning will significantly limit needed discretion to conduct such planning, and that, without discretion to adjust the scenario modeling and assumptions to regional circumstances, the final order could lead to more delay and conflict.³⁷⁹ MISO TOs contend that the NOPR proposals vary sufficiently from MISO's current approach that MISO and its stakeholders will need to engage in complex and time-intensive revisions in order to comply.³⁸⁰ Similarly, City of New Orleans Council asks that the final order not hinder existing MISO processes.³⁸¹

152. Multiple commenters recommend that the Commission's final order establish principles and objectives for long-term transmission planning that address the Commission's concerns and provide transmission providers with the flexibility to develop tailored long-term transmission planning approaches and implementation details accordingly.³⁸² MISO recommends that each transmission provider should give the Commission a report outlining the actions and processes that support the Commission's principles and guidance, and then the Commission could direct specific changes within each transmission planning region as it deems necessary.³⁸³

153. Multiple commenters argue for flexibility to accommodate local and regional differences, including differences in public policy goals that affect transmission planning.³⁸⁴ NYISO asks that the final order give each transmission planning region discretion to determine, in coordination with state entities and stakeholders, how best to

incorporate the Long-Term Regional Transmission Planning requirements within its transmission planning framework.³⁸⁵ California Municipal Utilities add that a significant amount of demand in the West is served by publicly-owned utilities and electric cooperatives, which fall outside of state commission regulation, highlighting the need for flexibility in planning.³⁸⁶

154. Dominion asserts that any reforms adopted in this proceeding should align with the purpose of the transmission system, which is to provide reliable, affordable electric service to customers rather than to benefit generators.³⁸⁷

155. APPA agrees with concerns expressed by Commissioner Christie and former Commissioner Danly that overly prescriptive transmission planning requirements have the potential to interfere with existing regional transmission planning processes, and hence argues that adequate flexibility is needed.³⁸⁸ Mississippi Commission states that where an RTO/ISO or non-RTO/ISO transmission provider is already engaged in long-term regional transmission planning, the Commission should accept flexibility and regional variations on compliance to address region-specific issues, including the delineation of regional and local transmission facilities through, for example, a voltage threshold (e.g., 100 kV).³⁸⁹

156. CAISO maintains that the Commission should allow it to continue evaluating transmission needs driven by Public Policy Requirements in its transmission planning process, in addition to any Long-Term Regional Transmission Planning process, and give CAISO the flexibility to continue using resource portfolios and geographic zones identified by state agencies and local regulatory authorities.³⁹⁰ Although ACORE urges the Commission not to grant requests for less stringent transmission planning requirements in the final order, ACORE agrees that there may be cases where an individual RTO's/ISO's existing processes may be superior to the proposed reforms, such as in the case of CAISO's treatment of

public policy projects within its annual transmission planning process.³⁹¹ California Municipal Utilities note that CAISO has already begun to implement some of the key reforms that the Commission proposed in the NOPR, specifically by adopting a 20-year outlook for transmission planning.³⁹²

157. MISO requests that a final order support, rather than detract from, its demonstrated success in long-term transmission planning.³⁹³ MISO TOs request that the Commission revise the NOPR's required parameters for Long-Term Regional Transmission Planning to accommodate the robust long-term regional transmission planning that some transmission planning regions, like MISO, have already developed.³⁹⁴ Similarly, Ameren contends that the Commission should find that MISO's approved Long Range Transmission Planning process substantially complies with the proposed reforms.³⁹⁵

158. New York TOs support allowing transmission planning regions with already successful transmission planning processes to retain those processes while making incremental enhancements and to demonstrate on compliance that they meet the NOPR's objectives.³⁹⁶ New York Transco asserts that the current NYISO public policy transmission planning processes already address, at least in part, the proposed reforms and believes that the Commission should permit regional flexibility.³⁹⁷

159. SPP states that its current transmission planning processes are sufficient to meet the intent of the Commission's proposed Long-Term Regional Transmission Planning reforms.³⁹⁸ Omaha Public Power states that SPP and other RTOs/ISOs have already developed long-term planning scenarios and suggests that transmission providers that already have long-term planning scenarios should be provided with the flexibility to continue using their previously established processes.³⁹⁹

160. In contrast, some commenters argue that the final order should not provide too much flexibility to transmission providers because that flexibility will undermine Long-Term

at 4–5; MISO Initial Comments at 23; NEPOOL Initial Comments at 7; NYISO Initial Comments at 11; PG&E Initial Comments at 2; PJM Initial Comments at 54–55; US Chamber of Commerce at 4–5.

³⁷⁹ Ameren Initial Comments at 8; ISO–NE Initial Comments at 20; ISO/RTO Council Initial Comments at 8–9; MISO TOs Reply Comments at 10–12.

³⁸⁰ MISO TOs Reply Comments at 10–11.

³⁸¹ City of New Orleans Initial Comments at 5–6.

³⁸² ISO–NE Initial Comments at 20; ISO/RTO Council Initial Comments at 4–5, 8–9; MISO Initial Comments at 22–23.

³⁸³ MISO Initial Comments at 22.

³⁸⁴ APPA Reply Comments at 9–10; California Commission Initial Comments at 5; California Municipal Utilities Reply Comments at 2–4; Industrial Customers Reply Comments at 4; Louisiana Commission Reply Comments at 4–5; Georgia Commission Initial Comments at 2; NARUC Initial Comments at 3; New York Transco Initial Comments at 5; North Dakota Commission Initial Comments at 3; New York Commission and NYISERDA Initial Comments at 3; OMS Initial Comments at 3; PJM States Initial Comments at 2.

³⁸⁵ NYISO Initial Comments at 13.

³⁸⁶ California Municipal Utilities Reply Comments at 2.

³⁸⁷ Dominion Initial Comments at 5.

³⁸⁸ APPA Initial Comments at 23.

³⁸⁹ Mississippi Commission Reply Comments at 7–8 (citing Entergy Initial Comments at 2–4; Louisiana Commission Initial Comments at 35–36; Michigan State Entities Initial Comments at 2; MISO Initial Comments at 2–3, 19; MISO TOs Initial Comments at 2, 4, 13–15).

³⁹⁰ CAISO Reply Comments at 17–18.

³⁹¹ ACORE Reply Comments at 4.

³⁹² California Municipal Utilities Initial Comments at 5.

³⁹³ MISO Reply Comments at 2–3.

³⁹⁴ MISO TOs Reply Comments at 11–12.

³⁹⁵ Ameren Initial Comments at 8.

³⁹⁶ New York TOs Initial Comments at 8–9.

³⁹⁷ New York Transco Initial Comments at 5.

³⁹⁸ SPP Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at P 3).

³⁹⁹ Omaha Public Power Initial Comments at 4.

Regional Transmission Planning.⁴⁰⁰ Many commenters opposing greater flexibility argue that the Commission should establish minimum requirements for Long-Term Regional Transmission Planning.⁴⁰¹

161. AEP argues that the Commission must resist requests for excessive regional flexibility that could threaten the development of long-term regional transmission and only permit it in limited instances that exceed minimum requirements.⁴⁰² Onward Energy states that, while flexibility is reasonable, the Commission must clearly identify who will drive regional transmission planning processes and how transmission planners will coordinate, study, and implement Long-Term Scenarios that represent realistic future resource portfolios.⁴⁰³ Clean Energy Associations state that without robust and proactive transmission planning rules, the Commission cannot determine that rates remain just and reasonable.⁴⁰⁴ DC and MD Offices of People's Counsel state that, while regional flexibility is critical, long-term transmission planning rules that provide carve-outs and opt-outs will result in balkanized transmission development.⁴⁰⁵

162. Hannon Armstrong states that by diluting the proposed requirements or granting flexibility as some commenters request, the Commission would allow existing deficiencies to persist, enabling the continued reliance on either the generator interconnection process or operational planning to resolve or mitigate constraints.⁴⁰⁶ Invenergy rebuts commenters' claims that the NOPR is too prescriptive or that some of the NOPR requirements should be optional, stating that optional processes and

deference to regional flexibility will not ensure needed transmission is built and that a flexible approach has already been tried and has failed to produce sufficient results.⁴⁰⁷

c. Comments Regarding More Comprehensive Transmission Planning

163. Several commenters contend that Long-Term Regional Transmission Planning should not interfere with and should not supplant existing shorter-term transmission planning processes.⁴⁰⁸ PJM asks the Commission to confirm that it did not mean for the NOPR proposals on Long-Term Regional Transmission Planning to modify the existing reliability and market efficiency transmission planning processes.⁴⁰⁹ Transmission Dependent Utilities encourage the Commission to ensure that transmission providers do not focus on long-term objectives to satisfy state renewable energy portfolio requirements to the detriment of near-term reliability needs, such as end-of-life transmission planning.⁴¹⁰ Large Public Power and NEPOOL state that any final order should clearly state that the current near-term transmission planning rules and processes, especially cost allocation, are not changed by the final order's reforms, except where expressly indicated.⁴¹¹ Ameren argues that the Commission was clear that changes to existing reliability and economic transmission planning requirements are beyond the scope of the NOPR and that the comments filed supporting holistic planning have provided no compelling basis for the Commission to address them.⁴¹²

164. Several commenters contend that Long-Term Regional Transmission Planning should not interfere with and must not supplant existing shorter-term transmission planning processes for transmission needs driven by Public Policy Requirements.⁴¹³ CAISO states that the NOPR provides no guidance or

criteria regarding how a transmission provider can demonstrate that its existing process for addressing transmission needs driven by Public Policy Requirements does not interfere with or undermine Long-Term Regional Transmission Planning. CAISO contends that it should not have to re-justify its existing process or demonstrate that its existing process is consistent with or superior to Long-Term Regional Transmission Planning.⁴¹⁴

165. AEP asserts that transmission providers should look at nearer-term reliability and economic transmission planning processes to determine whether there are needs that can be incorporated into Long-Term Regional Transmission Planning and addressed by a Long-Term Regional Transmission Facility.⁴¹⁵ SEIA recommends that the Commission require transmission providers to engage in portfolio-based transmission planning that integrates all relevant factors, including near-term needs, into Long-Term Regional Transmission Planning.⁴¹⁶ Policy Integrity argues that inclusion of specific requirements for transmission modeling are needed to fulfill the mandate of ensuring wholesale electric rates are just and reasonable.⁴¹⁷ Xcel recommends that the Commission require that known or expected generation be included in short-term regional transmission planning assumptions.⁴¹⁸

166. PIOs state that, if the two processes continue to exist, the Commission should mandate that the base cases used in Order No. 1000 regional transmission planning processes and Long-Term Scenarios in Long-Term Regional Transmission Planning be defined in the same process. Otherwise, PIOs contend, inconsistent assumptions between the two processes could lead to redundant transmission projects and failure to identify more efficient solutions. In particular, PIOs argue, if an Order No. 1000 transmission planning process base case identifies transmission needs that are not anticipated in the Long-Term Scenarios, the opportunities for more efficient planning created by the long-term process will be lost. In addition, PIOs suggest that there may be opportunities for stakeholders to undermine Long-Term Regional Transmission Planning if they believe Order No. 1000 transmission planning

⁴⁰⁰ See, e.g., ACORE Reply Comments at 2–4 (citing New Jersey Commission Initial Comments at 7); AEP Reply Comments at 2–5; Clean Energy Associations Reply Comments at 4–6; DC and MD Offices of People's Counsel Reply Comments at 2–3; Hannon Armstrong Reply Comments at 1; Interwest Reply Comments at 3–4; Invenergy Reply Comments at 8–10; PIOs Reply Comments at 5–6.

⁴⁰¹ See, e.g., AEE Reply Comments at 9–13, 16–18, 21–22; AEP Reply Comments at 2–5; Cypress Creek Reply Comments at 4–9; Interwest Reply Comments at 3–4; Invenergy Initial Comments at 2; Kentucky Commission Chair Chandler Reply Comments at 2; PIOs Reply Comments at 2–3; SEIA Reply Comments at 1–3; Southeast PIOs Reply Comments at 21–22; SREA Reply Comments at 26–27.

⁴⁰² AEP Reply Comments at 3.

⁴⁰³ Onward Energy Initial Comments at 4.

⁴⁰⁴ Clean Energy Associations Reply Comments at 4–5 (citing CAISO Initial Comments at 3; California Commission Initial Comments at 11; ISO-New England Initial Comments at 4; ISO/RTO Council Initial Comments at 8; NYISO Initial Comments at 3; PG&E Initial Comments at 4; PJM States Initial Comments at 4).

⁴⁰⁵ DC and MD Offices of People's Counsel Reply Comments at 2.

⁴⁰⁶ Hannon Armstrong Reply Comments at 1.

⁴⁰⁷ Invenergy Reply Comments at 9–10.

⁴⁰⁸ Ameren Reply Comments at 17; CAISO Initial Comments at 2–3, 17–20; Chemistry Council Initial Comments at 5; Dominion Initial Comments at 23; Exelon Initial Comments at 6–7; Indicated PJM TOS Initial Comments at 12; ITC Initial Comments at 8–9; Large Public Power Initial Comments at 14–16; NEPOOL Initial Comments at 8; NESCOE Initial Comments at 21–23; PJM Initial Comments at 55–57; PPL Initial Comments at 4–5; Transmission Dependent Utilities Initial Comments at 4–6; WIRES Initial Comments at 6–7; Xcel Initial Comments at 16.

⁴⁰⁹ PJM Initial Comments at 55–57.

⁴¹⁰ Transmission Dependent Utilities Initial Comments at 4–6.

⁴¹¹ Large Public Power Initial Comments at 16–18; NEPOOL Initial Comments at 7–8.

⁴¹² Ameren Reply Comments at 17.

⁴¹³ Anbaric Initial Comments at 22–27; CAISO Initial Comments at 2–3, 9–20; Large Public Power Initial Comments at 14–16.

⁴¹⁴ CAISO Initial Comments at 19.

⁴¹⁵ AEP Initial Comments at 10.

⁴¹⁶ SEIA Initial Comments at 20–21.

⁴¹⁷ Policy Integrity Supplemental Comments at 3.

⁴¹⁸ Xcel Initial Comments at 16.

would produce more favorable results for them. PIOs further argue that because uncertainty grows the further one looks into the future, there should not be significant differences in the short-term results of Long-Term Regional Transmission Planning and Order No. 1000 regional transmission planning processes.⁴¹⁹

167. Several commenters support forward-looking, Long-Term Regional Transmission Planning but argue for holistic planning using multiple drivers of transmission needs.⁴²⁰ They argue that a holistic approach is more efficient, better accounts for long-term benefits of new transmission, addresses the needs of more stakeholders, and is more likely to support development of regional transmission facilities, among other benefits. Competition Advocates support a final order that reflects the benefits of holistic modeling,⁴²¹ while New Jersey Commission contends that holistic transmission planning using a competitive process provides significant benefits, including reducing costs.⁴²²

168. To ensure that reforms are not undermined by existing processes, Clean Energy Buyers recommend that the Commission extend to all existing regional transmission planning processes—not just transmission planning processes to address transmission needs driven by Public Policy Requirements, as proposed in the

NOPR—the requirement that, on compliance with any final order, transmission providers who seek to retain existing regional transmission planning and cost allocation processes must demonstrate that continued use of those processes does not interfere with or undermine Long-Term Regional Transmission Planning.⁴²³

169. However, other commenters support the Commission's proposal in the NOPR to *not* apply the proposed reforms to existing Order No. 1000 reliability and near-term economic regional transmission planning processes.⁴²⁴ Ohio Consumers support the NOPR's proposal to mostly retain the regional transmission planning processes outlined in Order No. 1000, explaining that PJM stakeholders have reached an effective settlement under that framework in which costs are allocated in a manner that is roughly commensurate with the benefits received.⁴²⁵

170. Some commenters argue that the Commission should require that local transmission projects be evaluated and approved as part of a holistic planning approach.⁴²⁶ AEE asserts that, to ensure that transmission providers consider the full range of needs in developing long-term regional transmission plans, the final order should require them to consider local transmission plans and to determine whether a regional solution would be more efficient or cost-effective.⁴²⁷ OMS suggests that the Commission require that all local transmission projects be evaluated and approved as part of regional transmission planning processes with the opportunity for meaningful input from retail regulators, which it argues will enable participation by state regulators while respecting transmission owners' abilities to maintain their systems.⁴²⁸

171. By contrast, WIRES argues that the Commission should maintain the distinction between regional transmission planning and local transmission planning. WIRES argues that, while the regional transmission planning process is directed toward addressing certain reliability concerns, economic criteria, and public policy

initiatives, it is not geared toward addressing additional system needs related to resilience, asset management, customer needs, customer impact, and aging infrastructure replacement that is typically the focus of local transmission planning.⁴²⁹ Similarly, AEP states that if an RTO/ISO were to make all decisions regarding local transmission projects, they would also need to assume the accompanying responsibility—and the liability—for such decisions, which would entail physical inspection and condition assessment of assets, as well as a determination of when transmission facilities have reached their end of useful life.⁴³⁰ AEP points out that both CAISO and PJM have expressly stated that they do not wish to undertake these types of activities and assume such obligations.⁴³¹

d. Concerns Regarding Favoring Renewable Resources

172. ELCON argues that the Commission's proposal could require customers to pay higher costs to connect distant renewables when a lower-cost transmission project would provide the same reliability or economic benefits.⁴³² Utah Division of Public Utilities states that Long-Term Scenario requirements favoring renewable generation burden transmission providers while providing little to no benefit and that developers and generation utilities should determine which renewable generation should be developed at their respective zones or sites.⁴³³ Utah Commission further contends that nationwide mandates for transmission planning add costs, produce confusion, and create conflicts that could lead to higher utility prices for consumers.⁴³⁴ Kansas Ratepayer Advocates contend that Long-Term Regional Transmission Planning would presume material additions of renewable energy to serve consumers within a state, coupled with material additions of transmission to interconnect those renewables to the electric transmission grid, which do not reflect the unique circumstances of Kansas.⁴³⁵

173. Vistra asserts that the proposed reforms could devolve into the subsidization of resources chosen to

⁴¹⁹ PIOs Initial Comments at 44–46.

⁴²⁰ See, e.g., Acadia Center and CLF Initial Comments at 4–7; ACEG Initial Comments at 6–7, 30–31; ACORE Initial Comments at 5–7; Anbaric Initial Comments at 5–10; AEE Reply Comments at 2; Business Council for Sustainable Energy Initial Comments at 2; City of New York Initial Comments at 4–6; Competition Coalition Initial Comments at 15–16; Cypress Creek Reply Comments at 4–5; Enel Initial Comments at 3; Pine Gate Initial Comments at 18–19; PIOs Reply Comments at 11; SEIA Reply Comments at 2, 7–8; see also Pattern Energy Initial Comments at 16.

⁴²¹ Competition Advocates Supplemental Comments at 1; see also Policy Integrity Supplemental Comments at 2–3 (citing Jennifer Danis *et al.*, Inst. for Policy Integrity, *Transmission Planning for the Energy Transition: Rethinking Modeling Approaches* (Dec. 2023), https://policyintegrity.org/files/publications/Transmission_Report_2023.pdf).

⁴²² New Jersey Commission Motion to Lodge at 4–5 (citing *In re Declaring Transmission to Support Offshore Wind a Pub. Policy of the State of N.J.*, Order on the State Agreement Approach SAA Proposals, N.J. BPU Docket No. QO20100630 (Oct. 26, 2022), https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1279919; Johannes P. Pfeifenberger, *et al.*, Brattle Grp., *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report*, (Oct. 26, 2022), https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1279916; PJM, *Economic Analysis Report: 2021 SAA Proposal Window to Support NJ OSW* (Nov. 4, 2022), <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221104-special-informationalonly---njosw-economic-analysis-report.ashx>).

⁴²³ Clean Energy Buyers Initial Comments at 9–10.

⁴²⁴ Ameren Reply Comments at 17; Exelon Initial Comments at 6–7; ITC Initial Comments at 8–9; WIRES Initial Comments at 6–7.

⁴²⁵ Ohio Consumers Initial Comments at 7 (citing NOPR, 179 FERC ¶ 61,028 at P 72).

⁴²⁶ AEE Initial Comments at 3, 38; OMS Initial Comments at 16–17; LS Power and NRG Supplemental Comments at 34–37.

⁴²⁷ AEE Initial Comments at 3, 38.

⁴²⁸ OMS Initial Comments at 16–17.

⁴²⁹ WIRES Initial Comments at 9.

⁴³⁰ AEP Reply Comments at 7.

⁴³¹ *Id.* (citing *S. Cal. Edison Co.*, 164 FERC ¶ 61,160, at P 18 (2018); PJM Interconnection, L.L.C., Comments of PJM, Docket No. ER20–2308–000, at attach. A (July 2, 2020) (citation omitted)).

⁴³² ELCON Initial Comments at 9–10.

⁴³³ Utah Division of Public Utilities Initial Comments at 7–8.

⁴³⁴ Utah Commission Initial Comments at 11, 13.

⁴³⁵ Kansas Ratepayers Advocates Reply Comments at 2.

achieve state policy goals, masking the true costs of those remotely located resources that require extensive transmission development to interconnect to the grid and leading to market distortions that undermine the objectives of these reforms.⁴³⁶

174. Louisiana Commission states that the NOPR would result in subsidization of the costs of transmitting remote renewable energy, spreading the costs out broadly based on an expanded “nebulous concept of ‘benefits’ and perceived ‘public policy,’” thus ensuring that those transmission projects will pass any economic test.⁴³⁷ According to Louisiana Commission, this subsidization would interfere with price signals, thereby distorting the efficient functioning of the wholesale market.⁴³⁸ Louisiana Commission states that any Commission policy should be resource and technology neutral and should not impose costs on states that do not benefit from distant renewable power.⁴³⁹

175. Finally, Louisiana Commission contends that the NOPR’s long-term transmission planning requirements could threaten the reliability of the transmission grid because the intermittent renewable resources that the NOPR favors do not provide stable output and are not dispatchable.⁴⁴⁰ Similarly, former Kansas Commission Chair Keen argues that the NOPR fails to acknowledge the reliability concerns associated with a generation mix that is too heavily weighted to intermittent renewable generation resources.⁴⁴¹

e. Concerns Regarding Uncertainty, Over-Building, and Costs

176. A few commenters argue that long-term transmission planning introduces uncertainty or incentivizes speculative transmission development.⁴⁴² While EPSA acknowledges that long-term forecasts can provide valuable information about the potential scale of construction necessary to achieve decarbonization, it argues that using such forecasts to

justify investment shifts the risks to consumers from developers and facility owners.⁴⁴³ California Municipal Utilities state that, as transmission planning horizons are extended, the changes in resource mix, technology types, the location of resources, and demand will likely change congestion patterns and therefore the need for transmission upgrades needed to address them.⁴⁴⁴

177. Louisiana Commission states that it opposes the NOPR proposal because it would lead to an inefficient and expensive build-out of the transmission system and could be used to justify shifting the costs of this build-out to load.⁴⁴⁵ ELCON states that it is concerned that the Commission’s proposal to prioritize Long-Term Regional Transmission Planning to connect renewable generation over Long-Term Regional Transmission Planning for economically necessary transmission may exceed the Commission’s authority if it increases transmission rates for the benefit of a few stakeholders.⁴⁴⁶ Southern states that transmission expansion predicated on hypothetical resources that might not materialize would not satisfy the fundamental legal requirements of being used and useful, prudent, and/or otherwise needed for the public use, could harm reliability, and would violate the Commission’s duty under the FPA to facilitate transmission planning to meet load-serving entities’ obligations.⁴⁴⁷

178. Industrial Customers argue that the NOPR does not provide evidence that extending the transmission planning horizon would exclude modeling of speculative projects, which would likely result in the over-building of transmission and unnecessary increases in rates.⁴⁴⁸ Industrial Customers cite the D.C. Circuit’s finding in *Old Dominion Electric Cooperative v. FERC* that “[w]e are sensitive to the concern . . . that individual utilities should not have free rein to impose unjustified costs on an entire region by unilaterally adopting overly ambitious planning criteria,” and argue that the current NOPR proposal would result in the same issues.⁴⁴⁹

179. NRG urges caution on over-reliance on any 20-year planning study for making transmission investments due to the inherent uncertainty of a study with such a long planning horizon.⁴⁵⁰ NRG argues that the NOPR will increase delivery costs by reducing the value of private investments and replacing such investments with a centrally planned, cost-socialized approach that is founded on at least some incorrect assumptions.⁴⁵¹ NRG provides several examples of how forecast errors have caused adverse consequences, including forecasts of natural gas prices, load forecasts, and canceled planned transmission facilities.⁴⁵²

180. Likewise, Ohio Consumers urge the Commission to avoid adopting proposals based on long-term projections that justify massive charges to consumers based on hypothetical scenarios.⁴⁵³ Ohio Consumers state that Ohio customers have recently been saddled with rate increases in part due to transmission investments and that long-term transmission planning requirements would increase ratepayer burden, which is especially troublesome if projections turn out to be inaccurate.⁴⁵⁴

181. As an alternative to Long-Term Regional Transmission Planning, Potomac Economics states that the Commission could require the transmission planning process to incorporate a broader array of near-term emerging trends that are less uncertain than the proposed longer-term factors.⁴⁵⁵ Louisiana Commission states that it shares Potomac Economics’ concerns. Louisiana Commission urges the Commission to heed testimony submitted by Potomac Economics arguing that: (1) there is significant uncertainty about future technology and a significant risk of investing in transmission projects that will not ultimately provide value; (2) large transmission projects are often not the most economic, whereas smaller, targeted projects are more beneficial; and (3) there can and likely would be stranded transmission if transmission planning processes attempt to identify and meet transmission needs 20 to 30 years in the future.⁴⁵⁶

182. US Chamber of Commerce argues that the Commission should ensure that any Long-Term Regional Transmission

⁴³⁶ Vistra Initial Comments at 11.

⁴³⁷ Louisiana Commission Reply Comments at 12 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm’r, concurring at P 2)).

⁴³⁸ Louisiana Commission Initial Comments at 19–21.

⁴³⁹ *Id.* at 21–24.

⁴⁴⁰ *Id.* at 21–23. *But see* Cypress Creek Reply Comments at 2–4 (disagreeing with Louisiana Commission and claiming that regionally coordinated transmission planning should provide demonstrable system reliability benefits).

⁴⁴¹ Kansas Commission Chair Keen Initial Comments at 1.

⁴⁴² EPSA Initial Comments at 7; New England Systems Initial Comments at 22; *see also* NRECA Initial Comments at 28–29.

⁴⁴³ EPSA Initial Comments at 7.

⁴⁴⁴ California Municipal Utilities Initial Comments at 7.

⁴⁴⁵ Louisiana Commission Initial Comments at 4–5.

⁴⁴⁶ ELCON Initial Comments at 9 (citing NOPR, 179 FERC ¶ 61,028 (Danly, Comm’r, dissenting, at P 2 n.3); NOPR, 179 FERC ¶ 61,028 at P 47).

⁴⁴⁷ Southern Initial Comments at 32, 34.

⁴⁴⁸ Industrial Customers Initial Comments at 6, 15–16, 19–21.

⁴⁴⁹ *Id.* at 16 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1263 (D.C. Cir. 2018)).

⁴⁵⁰ NRG Initial Comments at 8.

⁴⁵¹ *Id.* at 3.

⁴⁵² *Id.* at 10–11.

⁴⁵³ Ohio Consumers Initial Comments at 5.

⁴⁵⁴ *Id.*

⁴⁵⁵ Potomac Economics Initial Comments at 4.

⁴⁵⁶ Louisiana Commission Reply Comments at 13–14.

Planning reforms do not perpetuate an irrational transmission buildout that undermines competitive advantages of domestic electricity rates. US Chamber of Commerce asserts that the loss of competitive advantage would lead to lost jobs, lost economic growth, decreased electricity use, and fixed system costs assessed to fewer customers.⁴⁵⁷

183. Vistra states that the proposed reforms lean toward accounting for regulatory and public policy initiatives that may shape changes in the generation mix without sufficiently incorporating the commercial and markets-related aspects of generation development.⁴⁵⁸ Vistra states that, without a process to assess commercial interest and financial commitment from generation developers, long-term regional transmission plans may under- or over-build transmission facilities or build them in the wrong locations.⁴⁵⁹ Relatedly, NRECA states that planning a regional transmission network for generation resources or changes in demand not identified by load-serving entities' forecasts, and instead through unsupported top-down assumptions, may produce uneconomic results from over-building and increase reliability risks.⁴⁶⁰

184. NRG states that, in light of the uncertainty of variables such as the amount of electrification and resulting load requirements, technology costs for new resources, and viability and repurposing of existing resources, it is not clear whether a "no regrets" option genuinely exists. NRG also asserts that the centralized planning envisioned in the NOPR sacrifices the ability of market participants to use available information to assess whether their investments will be viable in the future, which is a critical feature of competition. NRG asserts that the Commission has not contemplated that trade-off or quantified its costs, noting that past long-term transmission planning studies have done a questionable job at forecasting future needs.⁴⁶¹

185. Other commenters, however, note that the NOPR proposal includes measures that mitigate the uncertainty inherent in longer-term regional transmission planning.⁴⁶² For example, New Jersey Commission states that the proposed requirements to develop multiple scenarios and perform

reassessments mitigates the uncertainty inherently present in a 20-year transmission planning horizon.⁴⁶³ Additionally, several commenters rebut opposition to Long-Term Regional Transmission Planning based on concerns that it presents unreasonable levels of uncertainty.⁴⁶⁴ For example, SREA and Clean Energy Buyers assert that periodic updates of forecasts and scenarios will help to mitigate uncertainty.⁴⁶⁵

186. Policy Integrity further explains that future uncertainty is exactly why long-term scenario planning is necessary to ensure just and reasonable rates. Policy Integrity states that the current transmission planning process uses deterministic modeling that does not account for the changing world, which will not lead to the development of efficient or cost-effective transmission solutions. Policy Integrity asserts that, in contrast, long-term scenario planning will allow transmission planners to be prepared for changes.⁴⁶⁶ Policy Integrity argues that any forward-looking decision will have a degree of uncertainty, but that the risk posed by uncertainty can be mitigated and managed by using a portfolio evaluation of costs and benefits.⁴⁶⁷ Policy Integrity further argues that ignoring the uncertainty surrounding the energy transition runs its own risk of failing to build transmission that can be useful to meet needs in the short, medium, and long term.⁴⁶⁸

f. Concerns Regarding Incentives for Resource Development

187. Vistra asserts that it is critical for Commission policy to maintain interconnection cost signals to drive cost-effective generation siting choices.⁴⁶⁹ Vistra also argues that a policy that assigns all interconnection-related network upgrade costs, or even a disproportionately high share, to load undermines the incentive that generation developers currently have to site new projects in locations that minimize the related transmission upgrade costs.⁴⁷⁰

188. In contrast, New Jersey Commission argues that requiring individual interconnecting generators to

pay for piecemeal interconnection-related network upgrades does not necessarily encourage developers to make siting decisions that minimize the overall cost of integrating large amounts of new generation.⁴⁷¹ Likewise, Clean Energy Associations state that robust, proactive regional transmission planning will better incent efficient siting decisions, because generators will evaluate the likely costs of interconnection facilities that ensure deliverability to the grid, rather than more broadly beneficial transmission facilities.⁴⁷²

g. Comments Regarding Definition of Long-Term Regional Transmission Facility

189. PJM states that the Commission should clarify certain details of the NOPR proposal, including the meaning of the word "identified" in the proposed definition of Long-Term Regional Transmission Facility.⁴⁷³ In addition, PJM requests that the Commission clarify that if a transmission project shows up in several Long-Term Scenarios but is not selected until it reaches one of the shorter-term reliability and market efficiency transmission planning processes, that project would not be considered a Long-Term Regional Transmission Facility for selection and cost allocation purposes.⁴⁷⁴ Otherwise, PJM contends, the rules for selection and cost allocation for transmission projects selected in the shorter-term and intermediate-term reliability and market efficiency transmission planning processes will be unclear, leading to re-litigation.⁴⁷⁵

h. Challenges to Commission Jurisdiction or Authority

i. FPA Section 201

190. Some commenters argue that the NOPR proposals exceed the Commission's jurisdiction or that the Commission otherwise lacks the authority to adopt a final order in this proceeding. Of these commenters, most contend that the NOPR proposal interferes with authority reserved to the states under FPA section 201.⁴⁷⁶

⁴⁶³ New Jersey Commission Initial Comments at 10–11.

⁴⁶⁴ Clean Energy Buyers Reply Comments at 8; Policy Integrity Reply Comments at 2; SREA Reply Comments at 21–24.

⁴⁶⁵ Clean Energy Buyers Reply Comments at 8; SREA Reply Comments at 23.

⁴⁶⁶ Policy Integrity Reply Comments at 2.

⁴⁶⁷ *Id.* at 3–4.

⁴⁶⁸ *Id.* at 4.

⁴⁶⁹ Vistra Initial Comments at 7.

⁴⁷⁰ *Id.* at 7–8.

⁴⁷¹ New Jersey Commission Reply Comments at 7.

⁴⁷² Clean Energy Associations Reply Comments at 9 (citing ACEG 2021 Interconnection Report at 15).

⁴⁷³ PJM Initial Comments at 8, 98.

⁴⁷⁴ *Id.* at 99.

⁴⁷⁵ *Id.* at 99, 101.

⁴⁷⁶ Alabama Commission Initial Comments at 3–4, 7–8; Kansas Ratepayer Advocates Reply Comments at 2–3; Louisiana Commission Initial Comments at 5, 8–9, 27–28; Louisiana Commission Reply Comments at 14–15; Mississippi Commission Initial Comments at 3, 5–6; Mississippi Commission Reply Comments at 2; Nevada Commission Initial

⁴⁵⁷ US Chamber of Commerce Initial Comments at 8.

⁴⁵⁸ Vistra Initial Comments at 7.

⁴⁵⁹ *Id.*

⁴⁶⁰ NRECA Initial Comments at 18–19.

⁴⁶¹ NRG Initial Comments at 8.

⁴⁶² New Jersey Commission Initial Comments at 10–11; PIOs Initial Comments at 15–16.

191. Some commenters argue that the NOPR proposal intrudes on the authority reserved to the states under FPA section 201 over integrated resource planning processes or resource mix decision making.⁴⁷⁷ For example, Alabama Commission states that the NOPR proposal for Long-Term Regional Transmission Planning would intrude on state integrated resource planning to the extent that it dictates the construction of facilities through a top-down regional process or seeks to influence or mandate a substantive change to the generation resource mix.⁴⁷⁸ Similarly, Nevada Commission argues that the NOPR may impact states' authority to determine their own mix of generating resources. Nevada Commission contends that the NOPR may cross the line from regulating interstate transmission to regulating intrastate processes—particularly because the Commission has not asserted jurisdiction over bundled retail transmission.⁴⁷⁹ Louisiana Commission argues that the Commission should not override state jurisdiction on resource planning, fuel type, and siting decisions, along with the regulation of retail rates.⁴⁸⁰

192. Mississippi Commission requests that the Commission acknowledge that it cannot force regional planning entities to indirectly act as a national integrated resource planner.⁴⁸¹ SERTP Sponsors and Southern argue that the NOPR essentially constitutes a Commission-regulated integrated resource plan/request for proposal process and that, to be workable, Long-Term Regional Transmission Planning instead must be based on state commission-regulated

integrated resource planning/request for proposal decisions.⁴⁸² SERTP Sponsors and Southern contend that the NOPR proposed to require transmission providers to make independent resource and load decisions because: (1) state integrated resource plans are just one of many factors to be considered in developing Long-Term Scenarios; and (2) state integrated resource planning or request for proposal processes generally use a 10-year planning horizon such that there are no state-approved resources for the second half of the NOPR's proposed 20-year transmission planning horizon.⁴⁸³ SERTP Sponsors and Southern further argue that, in upholding Order No. 1000, the D.C. Circuit emphasized that the Commission was regulating the transmission planning process and not mandating any particular outcome, and that, if the Commission prescribes a process that supplants state decision making, it will have crossed the line into prescribing substantive outcomes and thus exceeded its jurisdiction.⁴⁸⁴

193. Ohio Commission Federal Advocate contends that the NOPR appears designed to target the achievement of narrow environmental policy objectives or the socialization of transmission costs, not to ensure reliability or foster just and reasonable rates.⁴⁸⁵ Southern and Utah Commission state that the Commission has consistently recognized that the FPA does not allow the Commission to pick winners and losers when it comes to generation and argue that the Commission has no authority to favor one generation mix over another.⁴⁸⁶ Similarly, Louisiana Commission, Kansas Ratepayer Advocates, and Undersigned States contend that the Commission lacks the statutory authority to dictate states' generation resource decisions. They argue instead that each state possesses such authority and is uniquely qualified to choose the generation resources that are needed to economically meet ratepayers' electric service needs within their states.⁴⁸⁷

194. SERTP Sponsors and Southern argue that, even if assumptions about the resource mix included in Long-Term Scenarios do not bind states, requiring transmission providers to develop Long-Term Scenarios that are predicated on particular resource assumptions effectively makes a substantive resource decision because it favors the assumed resource mix over others.⁴⁸⁸ SERTP Sponsors and Southern contend that this is akin to the Commission attempting to accomplish indirectly what it could not directly.⁴⁸⁹ SERTP Sponsors argue that the Commission should support the exercise of traditional state resource and infrastructure planning authority rather than supplant it.⁴⁹⁰ North Carolina Commission and Staff argue that the use of the production cost savings benefit in Long-Term Regional Transmission Planning “could conflict with state-jurisdictional resource decisions.”⁴⁹¹

195. Other commenters disagree with these contentions and argue that the NOPR proposal would not intrude on states' reserved authority over resource mix decision making or integrated resource plan processes.⁴⁹² Kentucky Commission Chair Chandler and SEIA argue that the NOPR's stated aim of reforming regional and interregional transmission planning processes does not foreclose states' decision making on generation.⁴⁹³ ACEG contends that the NOPR does not propose or purport to regulate the electric supply mix and that the Commission is acting squarely within its authority under the FPA's cooperative federalism structure.⁴⁹⁴ AEE notes that the Commission included integrated resource planning and utility load-serving planning as a factor driving transmission needs and argues that none of the requirements proposed by the Commission directly conflict with

Comments at 2–3, 6; SERTP Sponsors Initial Comments at 5, 15–19 & n.20; SERTP Sponsors Reply Comments at 12–13; Southern Initial Comments at 3–8, 12–13, 15–24; Southern Reply Comments at 3, 6–7; Utah Commission Initial Comments at 7–9; Undersigned States Reply Comments at 2, 4–5.

⁴⁷⁷ Alabama Commission Initial Comments at 3–4, 7–8; Kansas Ratepayer Advocates Reply Comments at 2; Louisiana Commission Initial Comments at 8–9, 27–28; Louisiana Commission Reply Comments at 14–15; Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2)); Nevada Commission Initial Comments at 2–3; SERTP Sponsors Initial Comments at 5, 15–19 & n.20; SERTP Sponsors Reply Comments at 12–13; Southern Initial Comments at 3–8, 12–13, 15–24; Southern Reply Comments at 3, 6–7; Utah Commission Initial Comments at 7–9; Undersigned States Reply Comments at 2, 4–5.

⁴⁷⁸ Alabama Commission Initial Comments at 3–4, 7–8.

⁴⁷⁹ Nevada Commission Initial Comments at 2–3.

⁴⁸⁰ Louisiana Commission Initial Comments at 27–28; Louisiana Commission Reply Comments at 14–15.

⁴⁸¹ Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2)).

⁴⁸² SERTP Sponsors Initial Comments at 15–16; SERTP Sponsors Reply Comments at 12–13; Southern Initial Comments at 4–5, 7, 15–16; Southern Reply Comments at 6–7.

⁴⁸³ SERTP Sponsors Initial Comments at 16; Southern Initial Comments at 12–13.

⁴⁸⁴ SERTP Sponsors Initial Comments at 19; Southern Initial Comments at 23–24 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 154).

⁴⁸⁵ Ohio Commission Federal Advocate Initial Comments at 4–6.

⁴⁸⁶ Southern Initial Comments at 23 (citing *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 26 (2018)); Utah Commission Initial Comments at 7–9.

⁴⁸⁷ Louisiana Commission Initial Comments at 8–10 (citing *Monongahela Power Co.*, 40 FERC

¶ 61,256, at 61,861 (1987); *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 212 (1983)); Kansas Ratepayer Advocates Reply Comments at 2; Undersigned States Reply Comments at 2, 4–5 (citing *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. at 205).

⁴⁸⁸ SERTP Sponsors Initial Comments at 17 n.20; Southern Initial Comments at 19.

⁴⁸⁹ SERTP Sponsors Initial Comments at 17 n.20; Southern Initial Comments at 18.

⁴⁹⁰ SERTP Sponsors Initial Comments at 17, 19; see also Undersigned States Reply Comments at 5, 8 (citing *Am. Gas Ass'n v. FERC*, 912 F.2d 1496, 1510 (D.C. Cir. 1990)).

⁴⁹¹ North Carolina Commission and Staff Initial Comments at 7.

⁴⁹² ACEG Reply Comments at 15; AEE Reply Comments at 23; New Jersey Commission Reply Comments at 2; Kentucky Commission Chair Chandler Reply Comments at 3; SEIA Reply Comments at 2–3.

⁴⁹³ Kentucky Commission Chair Chandler Reply Comments at 3; SEIA Reply Comments at 2–3.

⁴⁹⁴ ACEG Reply Comments at 15.

integrated resource planning processes, require that integrated resource planning be conducted on a different timeline, or override resource planning efforts.⁴⁹⁵ Likewise, Kentucky Commission Chair Chandler reiterates that Kentucky's integrated resource plans are not driving transmission planning processes in the state. He explains that integrated resource plans/requests for proposals are not the basis for generation investment decisions, but the state's requests for proposals seek generation proposals after the integrated resource planning process is complete and a need for generation is identified.⁴⁹⁶ In response to Alabama Commission's arguments that the NOPR's proposed rules have the potential to encroach on state-jurisdictional integrated resource planning and resource procurement processes overseen by Alabama Commission, SREA contends that Alabama Commission in fact does not have a formal integrated resource planning process upon which the Commission could encroach.⁴⁹⁷

196. New Jersey Commission disagrees with commenters who argue that the Commission intends to impose a preferred resource mix on the Nation by overriding state choices and contends that such arguments are "profoundly misconstruing" the nature of the NOPR proposal and what the Commission aims to achieve.⁴⁹⁸ Instead, New Jersey Commission argues that Long-Term Regional Transmission Planning would address transmission needs that are being driven by state policies, market decisions, and technological changes, all of which reflect consumer-driven demand for cleaner electricity.⁴⁹⁹ New Jersey Commission contends that the NOPR proposal would ensure that transmission needs are reliably met at a total cost that is just and reasonable, which New Jersey Commission argues is required—not precluded—by the FPA.⁵⁰⁰

197. Some commenters argue that the NOPR proposal would intrude on authority over siting and construction of transmission facilities that is reserved to the states under FPA section 201.⁵⁰¹ For

example, Southern argues that the FPA reserves transmission siting authority to the states and that the final order should not directly or indirectly interfere with this authority.⁵⁰² Alabama Commission argues that Long-Term Regional Transmission Planning would interfere with state authority to the extent it dictates the construction of facilities through a top-down regional process.⁵⁰³ Kansas Ratepayer Advocates state that the Commission would exceed its authority and violate states' constitutional rights by ordering states to construct interregional transmission facilities with construction costs paid by retail ratepayers in Kansas.⁵⁰⁴

198. Nevada Commission explains that Nevada law governs the issuance of permits to construct transmission facilities, and that such facilities—even where their costs are not intended to be recovered through retail rates—must go through and may not bypass that process in favor of regional transmission planning processes.⁵⁰⁵ NARUC contends that state participation in cost allocation for a portfolio of Long-Term Regional Transmission Facilities does not require a state, in its role as a transmission siting authority, to approve any projects within the portfolio.⁵⁰⁶

199. A few commenters argue that the NOPR proposal would intrude on the authority over certain transmission planning allegedly reserved to the states under FPA section 201. For example, Mississippi Commission states that the final order must respect state jurisdictional authority over planning and approval of transmission facilities used to serve state load.⁵⁰⁷ Nevada Commission states that Nevada will continue to plan for transmission through its integrated resource planning process and that the Commission should allow "bottom up" transmission planning, particularly in non-RTO/ISO transmission planning regions.⁵⁰⁸

200. In contrast, other commenters express support for the Commission's role in transmission planning. Ohio Consumers argue that the Commission has authority over transmission planning, even in states like Ohio that allow for retail consumer choice.⁵⁰⁹

SREA explains that states and other jurisdictional regulators will continue to have ultimate control over generation resource planning and transmission planning, regardless of what a regional transmission body proposes. SREA states that, even within RTO/ISO regions, "transmission or generation resource plans are subject to review, update or even cancellation, and those decisions are always determined by the relevant regulatory bodies."⁵¹⁰ Vistra states that any final order should recognize the legal and practical boundaries on the Commission's role in transmission development and in shaping the generation sector. According to Vistra, the Commission has successfully relied on its general authority under FPA sections 205 and 206 to oversee rates, terms, and conditions of jurisdictional service as the basis for its policies on transmission planning.⁵¹¹

201. Finally, Mississippi Commission argues that the NOPR proposal may infringe upon states' reserved authority under FPA section 201 to make resource adequacy decisions. Mississippi Commission explains that, when an RTO/ISO approves construction to deliver generation output to remote utilities that have failed to agree to purchase the energy, that RTO/ISO infringes on the state's resource adequacy jurisdiction.⁵¹² Mississippi Commission contends that requiring State A to pay for transmission upgrades to rely on energy generated in State B, despite State A having constructed its own generation facilities, would usurp State A's resource adequacy jurisdiction.⁵¹³

ii. "Major Questions Doctrine"

202. Some commenters argue that the NOPR proposal would not withstand judicial review under the major questions doctrine.⁵¹⁴

203. Louisiana Commission claims that the NOPR proposal violates principles of "agency law" and the separation of powers doctrine because Congress has not clearly delegated to the Commission the authority to enact far-reaching, nationwide policy changes favoring one form of generation over another.⁵¹⁵ Louisiana Commission

⁴⁹⁵ AEE Reply Comments at 23.

⁴⁹⁶ Kentucky Commission Chair Chandler Reply Comments at 6.

⁴⁹⁷ SREA Reply Comments at 2–3.

⁴⁹⁸ New Jersey Commission Reply Comments at 1–2.

⁴⁹⁹ *Id.* at 2.

⁵⁰⁰ *Id.*

⁵⁰¹ Alabama Commission Initial Comments at 7; Kansas Ratepayer Advocates Reply Comments at 3; NARUC Initial Comments at 29; Nevada Commission Initial Comments at 2–3; Southern Initial Comments at 21–22.

⁵⁰² Southern Initial Comments at 21–22.

⁵⁰³ Alabama Commission Initial Comments at 7.

⁵⁰⁴ Kansas Ratepayer Advocates Reply Comments at 3.

⁵⁰⁵ Nevada Commission Initial Comments at 2–3.

⁵⁰⁶ NARUC Initial Comments at 29.

⁵⁰⁷ Mississippi Commission Initial Comments at 5 (citing Mississippi Commission ANOPR Comments at 2, 17; NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at PP 2, 11–14)).

⁵⁰⁸ Nevada Commission Initial Comments at 6.

⁵⁰⁹ Ohio Consumers Initial Comments at 26 (citing *New York v. FERC*, 535 U.S. at 23–24, 26–28).

⁵¹⁰ SREA Reply Comments at 1–2.

⁵¹¹ Vistra Initial Comments at 4 & n.6.

⁵¹² Mississippi Commission Initial Comments at 5–6.

⁵¹³ *Id.* at 13.

⁵¹⁴ Louisiana Commission Initial Comments at 6, 12–13; Ohio Consumers Reply Comments at 14; SERTP Sponsors Initial Comments at 17–18; Southern Initial Comments at 20–21; Utah Commission Initial Comments at 8–9; Undersigned States Reply Comments at 3–4.

⁵¹⁵ Louisiana Commission Initial Comments at 6.

contends that the NOPR proposals exceed the limits of the FPA, which does not provide clear delegated authority for the Commission to decide types of generating resources. Louisiana Commission argues that the Commission therefore lacks the authority to determine whether the country should undergo a clean energy transition. Drawing parallels between the NOPR proposal and the U.S. Supreme Court's decision in *West Virginia v. EPA*, Louisiana Commission avers that the determination of what type of generating resources should be transmitted from where in the United States qualifies as a "major question" of public policy that Congress should order.⁵¹⁶

204. SERTP Sponsors argue that *West Virginia v. EPA* reinforces the need for the Commission to exercise restraint in expanding its jurisdiction without a clear Congressional delegation of authority.⁵¹⁷ According to SERTP Sponsors, *West Virginia v. EPA* makes clear that the Nation's energy policy and generation mix is a "major question" for which the Commission must have direct authorization from Congress to assert jurisdiction.⁵¹⁸ SERTP Sponsors contend that Congress has not clearly provided the Commission with jurisdiction to presuppose generation decisions and thereby effect particular substantive transmission outcomes.⁵¹⁹ Rather, SERTP Sponsors argue that Congress instead expressly and unequivocally reserved generation authority to the states.⁵²⁰

205. Southern similarly argues that *West Virginia v. EPA* makes clear that the Nation's energy policy and generation mix is a "major question" that requires more than a "merely plausible textual basis" for a Federal agency to assert jurisdiction.⁵²¹ Southern contends that, as applied to the NOPR proposal's "contemplated foray into [integrated resource planning and generation/resource matters]," the Commission does not rely upon a specific and clear grant of congressional authorization but instead relies upon its "general, gap-filling authorization in FPA Section 206 to regulate a 'practice' affecting a rate or charge for

transmission."⁵²² Southern contends that rather than provide clear congressional authorization, Congress instead reserved authority over integrated resource plans and generation to the states.⁵²³

206. Utah Commission argues that the Commission has no authority to enact any rule for the purpose of influencing the resource generation mix or expanding development of any type of generation. Utah Commission states that the increased development and integration of renewable generation is a "highly charged political question and a matter of significant political interest about which state legislatures have made very different policy choices." As such, Utah Commission argues that, although courts have given the Commission "some latitude under FPA Section 206," the U.S. Supreme Court will not uphold a final order premised upon the Commission's "claimed authority to prescribe a single, onerous national regime for transmission planning specifically intended to pressure transmission providers to select costly expansions into remote areas for the purpose of realizing [the Commission's] preferred generation mix, a matter specifically reserved to the states."⁵²⁴ Utah Commission explains that the Supreme Court's reasoning in *West Virginia v. EPA* is applicable to the Commission. Utah Commission argues that "imposing a single set of federally mandated, highly prescriptive transmission planning and cost allocation requirements for the purpose of privileging the selection of costly transmission projects to serve remote and speculative renewable generation is not a lawful exercise of [the Commission's] authority under FPA Section 206."⁵²⁵

207. Undersigned States argue that "[n]ational-scale energy grid regulation" is a "major question" because of the "massive economic consequences" involved and the implication of a "unique and complex jurisdictional divide between [s]tate and federal regulatory authority."⁵²⁶ According to Undersigned States, the Commission "has no statutory authority at all—much less 'clear congressional authorization'—to revamp the energy

grid's mix of generation resources writ large."⁵²⁷

208. Harvard ELI and Policy Integrity disagree with Undersigned States. They argue that Undersigned States "mischaracterize the NOPR" because the NOPR would not revamp the energy grid's mix of generation resources. Rather, according to Harvard ELI and Policy Integrity, the NOPR would require utilities to amend their existing regional transmission planning processes in response to changes in the resource mix and demand that are occurring because of factors unrelated to the NOPR.⁵²⁸

209. Harvard ELI and Policy Integrity also contend that Undersigned States overlook the major questions doctrine's key requirements. They assert that application of the major questions doctrine does *not* turn on whether a regulation will have significant economic effects or intrudes on areas traditionally regulated by states. Instead, Harvard ELI and Policy Integrity assert that the major questions doctrine is triggered only when an agency's action is both unheralded and transformative.⁵²⁹

210. Harvard ELI and Policy Integrity argue that the NOPR is not unheralded. They explain that Order No. 1000 similarly regulated transmission planning and cost allocation in response to concerns about the generation mix, and that the D.C. Circuit upheld Order No. 1000 while rejecting arguments similar to those that Undersigned States make here.⁵³⁰ Moreover, Harvard ELI and Policy Integrity identify provisions in existing tariffs that are similar to those that the NOPR proposes and point to other antecedents for Commission regulation of regional transmission planning.⁵³¹

211. Likewise, Harvard ELI and Policy Integrity argue that the NOPR does not represent a transformative expansion in the Commission's authority nor a "fundamental change to the statutory scheme."⁵³² Instead, they assert that the NOPR merely builds on existing regional transmission planning processes to ensure that Commission-jurisdictional rates remain just and reasonable, as the FPA requires.⁵³³

⁵¹⁶ *Id.* at 12 (citing 597 U.S. 697, 729–30, 735).

⁵¹⁷ SERTP Sponsors Initial Comments at 17 (citing *West Virginia v. EPA*, 597 U.S. at 723); see also EEI Initial Comments at 8 (urging the Commission to consider the overlap of the Commission's and state commissions' respective jurisdictions).

⁵¹⁸ SERTP Sponsors Initial Comments at 17–18.

⁵¹⁹ *Id.* at 18.

⁵²⁰ *Id.*

⁵²¹ Southern Initial Comments at 20–21 (citing *West Virginia v. EPA*, 597 U.S. at 723).

⁵²² *Id.*

⁵²³ *Id.* at 21.

⁵²⁴ Utah Commission Initial Comments at 8.

⁵²⁵ *Id.* at 8–9 (citing *West Virginia v. EPA*, 597 U.S. at 729–30).

⁵²⁶ Undersigned States Reply Comments at 3 (citing *West Virginia v. EPA*, 597 U.S. 697; *Ala. Ass'n of Realtors v. HHS*, 594 U.S. 758, 764 (2021)).

⁵²⁷ *Id.* at 4 (quoting *West Virginia v. EPA*, 597 U.S. at 723).

⁵²⁸ Harvard ELI and Policy Integrity Supplemental Comments at 2.

⁵²⁹ *Id.* at 2–3.

⁵³⁰ *Id.* at 4 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 48–49; Order No. 1000, 136 FERC ¶ 61,051 at PP 45, 47).

⁵³¹ *Id.* at 4–5; *id.* app. A.

⁵³² *Id.* at 6–7 (quoting *West Virginia v. EPA*, 597 U.S. at 723 (internal quotations omitted)).

⁵³³ *Id.*

iii. “Equal Sovereignty Doctrine”/Cross-Subsidization

212. Some commenters argue that the NOPR’s cost allocation proposal impermissibly requires states to subsidize other states’ public policies.⁵³⁴ Undersigned States argue that the NOPR would exceed the Commission’s jurisdiction because it violates the Constitution’s equal sovereignty doctrine, which provides constitutional equality among the states.⁵³⁵ According to Undersigned States, the NOPR “sets up a scheme where one [s]tate can effectively require other [s]tates to subsidize their own vision of what resources should be used in electricity generation—a core, sovereign [s]tate function,” which risks “undue discrimination” among states.⁵³⁶ Mississippi Commission argues that unanimous agreement, rather than majority agreement, would be required for any *ex ante* default cost allocation method, as each state has sole jurisdiction within its boundaries.⁵³⁷

213. Louisiana Commission asserts that “group state oversight” is not equivalent to “state oversight,” and that the Commission should not adopt a rule that subjects one state’s will to majority override. Louisiana Commission further argues that the Commission should not enact rules that would “impose costs for projects selected under the proposed long-term planning criteria on unwilling states that do not benefit from those projects, even if those states are in the minority.” Louisiana Commission contends that the Commission should not attempt to override state jurisdiction simply because a majority of states in a region may support imposing costs on unwilling states that do not benefit from transmission projects favored by the majority.⁵³⁸ Louisiana Commission argues that states should not be required to cede their jurisdiction by engaging in any “consulting” committee structure required with respect to Long-Term Regional Transmission Planning,⁵³⁹ because granting each state one vote in a multi-state body cannot replace the

meaningful exercise of state jurisdiction within a state’s borders.⁵⁴⁰

214. Conversely, ACEG disputes these claims, which ACEG states are “incorrect and misconstrue the NOPR.”⁵⁴¹ ACEG highlights the fact that the NOPR does not include resource preferences in its proposed planning criteria, factors, or benefits, nor does the NOPR exclude consideration of non-renewable resources from transmission planning.⁵⁴² ACEG further notes that the NOPR proposes to direct transmission planners to plan the system to “meet transmission needs driven by changes in the resource mix and demand,” requiring transmission planners to consider the resource mix as a whole, which necessarily requires considering all types of resources.⁵⁴³ New Jersey Commission agrees, stating that the Commission did not propose in the NOPR “to unduly favor, mandate, or subsidize forms of generation,” but rather “to ensure that the bulk electricity system maintains reliability and satisfies evolving consumer demands, whether driven by public policy requirements or voluntary goals, at the lowest reasonable cost.”⁵⁴⁴

Moreover, New Jersey Commission argues, allocating the cost of Long-Term Regional Transmission Facilities only to those states with relevant public policy goals “would allow the remaining states to free ride, and effectively force the states with public policy goals to subsidize the provision of normal electricity service in other states in order to pursue their own policies.”⁵⁴⁵

i. Other Issues

215. NRECA requests that the Commission clarify that the final order, consistent with the Commission’s obligation under FPA section 217(b)(4), “is intended to facilitate and support ‘bottom-up’ transmission planning to meet the transmission needs of [load-serving entities] to provide reliable and economical service to consumers.”⁵⁴⁶

216. Some commenters argue that the final order will not withstand judicial scrutiny if it does not permit regional flexibility.⁵⁴⁷ For example, US Chamber of Commerce explains that the interstate power grid includes investor-owned

utilities, publicly-owned utilities, and electric cooperatives, which can be members of RTOs/ISOs, power pooling arrangements, joint-ownership agreements, or subject to traditional vertically-integrated structures.⁵⁴⁸ According to US Chamber of Commerce, imposing a new regional transmission planning regime on all these various entities would ignore the compromises and benefits that led to the status quo.⁵⁴⁹ Relatedly, Southern and SERTP Sponsors argue that the legal viability of the final order will be threatened if the Commission fails to respect the FPA’s fundamental jurisdictional roles by not providing states and transmission providers with the opportunity and flexibility to adapt their planning processes.⁵⁵⁰

j. Miscellaneous Concerns

217. MISO seeks clarification from the Commission that the term “transmission planning region” has the same meaning as in Order No. 1000, where MISO may comprise a single transmission planning region despite including multiple transmission zones or local balancing authorities.⁵⁵¹

218. California Municipal Utilities state that transmission planning should not be a vehicle to centralize resource choices, but instead should reflect the choices made by state and local authorities.⁵⁵² Similarly, Mississippi Commission argues that Long-Term Regional Transmission Planning should be driven by state-specific concerns and needs and that regional priorities should be subordinated to state priorities.⁵⁵³ Mississippi Commission asks that the Commission not issue a final order but instead establish proceedings to address specific concerns with certain regional transmission planning processes on a more limited basis.⁵⁵⁴ Southern argues that Long-Term Regional Transmission Facilities in non-RTO/ISO transmission planning regions must have the support of affected states, as these facilities stem from resource and load assumptions that are not the result of those states’ planning and procurement processes.⁵⁵⁵ Southern urges the Commission to maintain the appropriate transmission

⁵³⁴ Alabama Commission Initial Comments at 9; Louisiana Commission Initial Comments at 29; Mississippi Commission Reply Comments at 3; Ohio Commission Federal Advocate Initial Comments at 4–5; Ohio Consumers Reply Comments at 14.

⁵³⁵ Undersigned States Reply Comments at 5–6 (citing *Coyle v. Smith*, 221 U.S. 559, 567 (1911)).

⁵³⁶ *Id.* at 6 (citing NOPR, 179 FERC ¶61,018, Danly, Comm’r, dissenting, at PP 4–5).

⁵³⁷ Mississippi Commission Reply Comments at 2–3.

⁵³⁸ Louisiana Commission Initial Comments at 27–28; Louisiana Commission Reply Comments at 14–16.

⁵³⁹ Louisiana Commission Initial Comments at 28–29.

⁵⁴⁰ Louisiana Commission Reply Comments at 16.

⁵⁴¹ ACEG Reply Comments at 18.

⁵⁴² *Id.* at 18–19.

⁵⁴³ *Id.* at 19.

⁵⁴⁴ New Jersey Commission Initial Comments at 3.

⁵⁴⁵ *Id.* at 20.

⁵⁴⁶ NRECA Initial Comments at 17–21.

⁵⁴⁷ SERTP Sponsors Initial Comments at 1; SERTP Sponsors Reply Comments at 1–2; Southern Initial Comments at 1; Southern Reply Comments at 3; US Chamber of Commerce Initial Comments at 4.

⁵⁴⁸ US Chamber of Commerce Initial Comments at 4.

⁵⁴⁹ *Id.*

⁵⁵⁰ Southern Initial Comments at 1; Southern Reply Comments at 3; SERTP Sponsors Initial Comments at 1; SERTP Sponsors Reply Comments at 1–2.

⁵⁵¹ MISO Initial Comments at 24.

⁵⁵² California Municipal Utilities Reply Comments at 2.

⁵⁵³ Mississippi Commission Initial Comments at 3.

⁵⁵⁴ *Id.* at 9.

⁵⁵⁵ Southern Initial Comments at 8.

planning and state-driven supply- and demand-side relationships, which Order No. 1000 preserved.⁵⁵⁶ SERTP Sponsors argue that the Commission should avoid mandates that could largely result in transmission expansion or infrastructure decisions that lead to investments borne, largely, by retail electricity consumers that lack the consent and support of the state authorities vested with the responsibility to protect those consumers.⁵⁵⁷

219. Several commenters agree with the Commission that any final order should apply to transmission providers in both RTO/ISO and non-RTO/ISO transmission planning regions.⁵⁵⁸ However, several commenters disagree and argue that the final order, or certain specified requirements in the final order, should apply only to RTO/ISO transmission planning regions.⁵⁵⁹ Nevada Commission argues that the RTOs/ISOs “may be better suited” than other regions for the transmission planning that the NOPR proposes.⁵⁶⁰ Utah Division of Public Utilities stresses the need for regional flexibility, noting that transmission providers located outside of RTOs/ISOs already coordinate on transmission planning with many non-Commission-jurisdictional entities.⁵⁶¹

220. SEIA rebuts the claims of Southern and Louisiana, Utah, Mississippi, and Alabama Commissions that state planning processes already interact well with transmission planning and support customers’ transmission needs.⁵⁶² SEIA and SREA assert that non-RTO/ISO transmission planning regions do not engage in sufficient or transparent transmission planning.⁵⁶³ Specifically, SEIA states, the transmission planning processes in non-RTO/ISO regions are rife with issues, including the use of inconsistent and inaccurate data and an exclusionary and insufficiently transparent process.⁵⁶⁴ Further, SEIA states that the end result of an integrated resource planning process may be based on inconsistent and inaccurate data,⁵⁶⁵ the

process is “sometimes disjointed,”⁵⁶⁶ and the process is a voluntary process in which the planning authority must accept, and not verify, the information provided.⁵⁶⁷

221. SREA rebuts Southern’s contention that Southern’s transmission planning processes are adequate, noting that Southern itself has presented testimony to the Georgia Commission conceding that it is unable to perform more robust transmission planning due to limitations in its software and models.⁵⁶⁸ SREA argues that throughout the Southeast, transmission planning is not a priority and that integrated resource planning is not a substitute for robust transmission planning.⁵⁶⁹ SREA explains that the NOPR borrows many of the qualities of integrated resource planning and applies them to transmission planning, including scenario-based evaluation and use of 20-year planning horizons, and that many states have integrated resource planning rules and guidelines that recognize the value of long-term planning.⁵⁷⁰

222. EPSA states that the Commission should focus not on socializing transmission costs but on reducing transaction costs, accelerating lagging processes, and adopting market-based solutions like open seasons.⁵⁷¹

223. GridLab states that there is evidence to suggest that changes in resource mix, demand, and weather will lead to significant changes in the value of regional transmission facilities in the 2030s, though GridLab asserts that these changes may increase or decrease the value of regional transmission facilities. Accordingly, GridLab recommends that the Commission and stakeholders resist evaluating the success of this rulemaking based on arbitrary metrics related to each transmission provider’s expansion of regional transmission facilities.⁵⁷²

3. Commission Determination

a. Participation in Long-Term Regional Transmission Planning

224. We adopt the NOPR proposal to require transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-

Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs.⁵⁷³ We also adopt the NOPR proposal to require that Long-Term Regional Transmission Planning comply with the following existing Order Nos. 890 and 1000 transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; and (6) dispute resolution.⁵⁷⁴ In developing their compliance filings, transmission providers and stakeholders should review the requirements set forth in Order No. 890 and Order No. 1000, and the Commission’s orders on compliance filings submitted by transmission providers, for guidance as to what each of these transmission planning principles requires. For example, as a starting point, a transmission provider should review the orders addressing its own Order Nos. 890 and 1000 compliance filings and the compliance filings for transmission providers in its transmission planning region.

225. We also adopt specific requirements regarding how transmission providers must conduct Long-Term Regional Transmission Planning. Specifically, and as discussed further below, we require transmission providers in each transmission planning region⁵⁷⁵ to: (1) identify Long-Term

⁵⁷³ We note that, while we have modified this definition of Long-Term Regional Transmission Planning from the NOPR proposal, the modified definition does not substantively change the steps involved in Long-Term Regional Transmission Planning from those proposed in the NOPR. Rather, the revised definition merely clarifies the steps that transmission providers must take in conducting Long-Term Regional Transmission Planning.

⁵⁷⁴ Order No. 1000, 136 FERC ¶ 61,051 at PP 146, 151. We do not address these principles in detail here.

⁵⁷⁵ In response to MISO’s request, MISO Initial Comments at 24, we clarify that this final order does not alter the meaning of “transmission planning region” as used in Order No. 1000. A transmission planning region is one in which transmission providers, in consultation with stakeholders and affected states, have agreed to participate for purposes of regional transmission planning and development of a single regional transmission plan. Order No. 1000–A, 139 FERC ¶ 61,132 at P 272; Order No. 1000, 136 FERC ¶ 61,051 at P 160.

⁵⁵⁶ *Id.* at 12.

⁵⁵⁷ SERTP Sponsors Initial Comments at 6–7.

⁵⁵⁸ See, e.g., AEE Reply Comments at 11; MISO Reply Comments at 3; PIOs Reply Comments at 2–3; SEIA Reply Comments at 5; SREA Initial Comments at 47; TAPS Initial Comments at 70.

⁵⁵⁹ See, e.g., Mississippi Commission Initial Comments at 16; Utah Division of Public Utilities Reply Comments at 1–2.

⁵⁶⁰ Nevada Commission Initial Comments at 2–4.

⁵⁶¹ Utah Division of Public Utilities Reply Comments at 1–2.

⁵⁶² SEIA Reply Comments at 5.

⁵⁶³ *Id.*; SREA Reply Comments at 15–17.

⁵⁶⁴ SEIA Reply Comments at 5–6.

⁵⁶⁵ *Id.* at 5 (citing Western PIOs Initial Comments at 10).

⁵⁶⁶ *Id.* (citing PacifiCorp and NV Energy Initial Comments at 10).

⁵⁶⁷ *Id.* (citing PacifiCorp and NV Energy Initial Comments at 13; Western PIOs Initial Comments at 11).

⁵⁶⁸ SREA Reply Comments at 7 (citing SREA Initial Comments, attach. B (Testimony of Georgia Power Witness Robinson) at 282–283).

⁵⁶⁹ *Id.* at 5.

⁵⁷⁰ *Id.*

⁵⁷¹ EPSA Initial Comments at 7–8.

⁵⁷² GridLab Initial Comments at 9–10.

Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs through the development of Long-Term Scenarios⁵⁷⁶ that satisfy the requirements set forth in this final order; (2) use and measure, at a minimum, a set of seven required benefits⁵⁷⁷ to evaluate Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of each transmission facility; and (3) evaluate Long-Term Regional Transmission Facilities to determine whether they are more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs and use selection criteria (in collaboration with states and other stakeholders) that provide the opportunity for transmission providers to select such Long-Term Regional Transmission Facilities.

226. These requirements together establish a long-term, forward-looking, and more comprehensive approach to regional transmission planning, which will ensure that transmission providers identify, evaluate, and select more efficient or cost-effective transmission solutions to address Long-Term Transmission Needs. Long-Term Regional Transmission Planning, as set forth in this final order, requires regional transmission planning based on a multitude of drivers of Long-Term Transmission Needs and provides the opportunity for transmission providers to meet those needs by selecting more efficient or cost-effective Long-Term Regional Transmission Facilities.

227. In considering the comments received on this proposal, we strike a careful balance. On the one hand, we believe that there is an inherent risk in transmission providers waiting for the near-term certainty that some commenters appear to believe is necessary⁵⁷⁸ before planning to address transmission needs. As explained in the Overall Need for Reform section above, doing so may result in transmission

providers relying on relatively inefficient and less cost-effective piecemeal transmission solutions to address these needs shortly before they manifest, to the detriment of customers. On the other hand, we acknowledge the inherent uncertainty involved in planning to meet Long-Term Transmission Needs and that this uncertainty means that forward-looking regional transmission planning entails certain risks, including the risk that transmission needs may change over time. In this final order, we balance these risks, requiring planning to meet Long-Term Transmission Needs, while imposing requirements on how Long-Term Regional Transmission Planning is conducted, as discussed further herein, to mitigate uncertainty. To adequately prepare for the future, transmission providers need to make decisions in the present that are grounded in a thorough, informed analysis of the factors that drive Long-Term Transmission Needs.

228. As discussed in the Overall Need for Reform section, these factors are together driving rapid changes in the Long-Term Transmission Needs that transmission providers must plan to meet to continue to provide an affordable, reliable supply of electricity to customers, but neither transmission infrastructure nor regional transmission planning processes are keeping pace. Consequently, the Commission's existing regional transmission planning requirements are no longer just and reasonable, as they increasingly result in transmission investment decisions occurring outside of regional transmission planning processes and instead through generator interconnection processes and local transmission planning processes that typically plan to meet discrete, nearer-term transmission needs. In addition, the record demonstrates that transmission providers have made substantial investments in in-kind replacement transmission facilities, which generally are not identified through more long-term, forward-looking, or comprehensive transmission planning. This final order aims to ensure that transmission providers, through their regional transmission planning processes, identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, helping to ensure just and reasonable rates.

229. We disagree with arguments that the Commission should not require Long-Term Regional Transmission Planning because, certain commenters claim, doing so will introduce excessive

uncertainty into regional transmission planning, transmission providers will make forecasting errors, or the final order will result in regional transmission planning that is speculative.⁵⁷⁹ To the contrary, we believe that the reforms adopted in this final order account for and seek to reduce the inherent uncertainty in forward-looking regional transmission planning, while ensuring that transmission providers, through their regional transmission planning processes, identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, thus helping to ensure just and reasonable rates.⁵⁸⁰ In fact, by requiring transmission providers to use Long-Term Scenarios in Long-Term Regional Transmission Planning, this final order provides transmission providers with a critical tool for managing uncertainty, facilitating regional transmission planning that accounts for a range of potential futures, as well as an assessment of the likelihood of each scenario manifesting, when identifying, evaluating, and selecting Long-Term Regional Transmission Facilities. Further, as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section below, we require transmission providers to reevaluate Long-Term Regional Transmission Facilities in certain circumstances, which will provide transmission providers with yet another such tool.

230. Moreover, notwithstanding allegations to the contrary, we believe that Long-Term Regional Transmission Planning is a logical and reasonable extension of current regional transmission planning processes, which also manage uncertainty and plan for future regional transmission needs. The key difference, which we address through this final order, is that these existing regional transmission planning processes are conducted in a manner that is not sufficiently long-term, forward-looking, or comprehensive such that transmission providers are not identifying Long-Term Transmission Needs. As a result, transmission providers are failing to identify or evaluate regional transmission facilities that would more efficiently or cost-effectively address those Long-Term Transmission Needs, and consequently,

⁵⁷⁶ The requirements related to Long-Term Scenarios are discussed below.

⁵⁷⁷ As discussed further below in the Evaluation of the Benefits of Regional Transmission Facilities section, these seven benefits are: (1) Benefit 1, Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement; (2) Benefit 2(a), Reduced Loss of Load Probability, or Benefit 2(b), Reduced Planning Reserve Margin; (3) Benefit 3, Production Cost Savings; (4) Benefit 4, Reduced Transmission Energy Losses; (5) Benefit 5, Reduced Congestion Due to Transmission Outages; (6) Mitigation of Extreme Weather Events and Unexpected System Conditions; and (7) Capacity Cost Benefits from Reduced Peak Energy Losses.

⁵⁷⁸ See, e.g., NRG Initial Comments at 8 (arguing that there are unlikely to be any "no regrets" options).

⁵⁷⁹ Louisiana Commission Initial Comments at 4–5; NRG Initial Comments at 3–4; Ohio Consumers Initial Comments at 5.

⁵⁸⁰ See Policy Integrity Initial Comments at 6 (arguing that future uncertainty requires scenario planning).

are missing the opportunity to select such regional transmission facilities. Our reforms in this final order remedy these deficiencies.

231. Further, we believe that Long-Term Regional Transmission Planning as set forth in this final order provides adequate safeguards against excessive transmission development in response to speculative transmission needs. For example, this final order requires transmission providers to develop multiple plausible and diverse Long-Term Scenarios based upon best available data, which will allow transmission providers to better understand how certain categories of factors will give rise to Long-Term Transmission Needs, and requires transmission providers to update their assumptions periodically, as discussed further below.⁵⁸¹ In developing these Long-Term Scenarios, transmission providers are required to treat more certain drivers of Long-Term Transmission Needs differently than less certain drivers, and must provide opportunities for stakeholder engagement. Further, the final order grants substantial flexibility to transmission providers to develop an evaluation process and selection criteria that will provide them with the opportunity to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without over-building transmission facilities. Consistent with the existing Order No. 1000 regional transmission planning processes, the final order does not require transmission providers to select any regional transmission facilities as part of Long-Term Regional Transmission Planning. Finally, we require transmission providers to reevaluate previously selected Long-Term Regional Transmission Facilities in certain circumstances, as discussed further below in the Reevaluation section.

232. The regional transmission planning and cost allocation requirements in this final order, like those of Order Nos. 890 and 1000, are focused on the transmission planning process, and do not require any substantive outcomes from this process.⁵⁸² We disagree with certain commenters' assertions that this final order favors, promotes, or subsidizes particular types of generation resources over others, or otherwise engages in

generation planning.⁵⁸³ Instead, this final order requires transmission providers to participate in Long-Term Regional Transmission Planning through their regional transmission planning process that identifies Long-Term Transmission Needs, evaluates the benefits of Long-Term Regional Transmission Facilities to meet those needs, and provides the opportunity for transmission providers to select Long-Term Regional Transmission Facilities that are more efficient or cost-effective transmission solutions to those needs. We reiterate that, as discussed below in the Evaluation and Selection of Long-Term Regional Transmission Facilities section, any selected Long-Term Regional Transmission Facilities must satisfy transmission provider-developed selection criteria that maximize benefits accounting for costs over time without over-building transmission facilities, which ensures that the costs of such transmission facilities are outweighed by the benefits they deliver to customers.

233. We disagree with commenters that argue that the factors giving rise to Long-Term Transmission Needs, such as state laws dictating specific generation resource mixes, are irreconcilable with effective transmission planning.⁵⁸⁴ These changes are occurring independent of any action that we take in this final order, and they are being driven by a wide variety of factors. This final order provides transmission providers with the tools that they need to respond to these factors, requiring that they conduct Long-Term Regional Transmission Planning to identify, evaluate, and select Long-Term Regional Transmission Facilities that are more efficient or cost-effective regional transmission solutions to the Long-Term Transmission Needs that these factors drive.

234. We disagree with Louisiana Commission and former Kansas Commission Chairman Keen's claims that Long-Term Regional Transmission Planning will threaten the reliability of the transmission system. We acknowledge that reliability needs are evolving; for example, the increasing frequency and severity of high-impact extreme weather events threatens grid reliability. We believe that Long-Term

Regional Transmission Planning—in addition to existing Order No. 1000 regional transmission planning and cost allocation requirements—is needed to support the reliable operation of transmission systems, given these changes. As the Commission and the North American Electric Reliability Corporation have noted, the transmission system may not be adequately prepared for extreme weather events and the increasing frequency of these events must be planned for to ensure system reliability.⁵⁸⁵ We thus view our action in this final order as complementary to other steps that the Commission has taken in recent years to bolster system reliability.⁵⁸⁶

235. Further, we disagree with the contention of Louisiana Commission and Vistra that Long-Term Regional Transmission Planning will distort the efficient functioning of Commission-jurisdictional wholesale markets by subsidizing uneconomic generation or by distorting price signals. As discussed further below, we require transmission providers, as part of Long-Term Regional Transmission Planning, to assess the costs and measure the benefits of regional transmission facilities that address Long-Term Transmission Needs and to develop evaluation processes and selection criteria that provide the opportunity to select those transmission facilities as more efficient or cost-effective regional transmission solutions to those Needs. While the addition of any new transmission facility necessarily affects Commission-jurisdictional wholesale markets, the requirements set forth in this final order ensure that transmission providers will have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities that provide value to transmission customers and support the efficient functioning of wholesale markets by addressing Long-Term Transmission Needs.

⁵⁸⁵ FERC, North American Electric Reliability Corporation, *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* (Nov. 2023), <https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022>; FERC, North American Electric Reliability Corporation, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 2021), <https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and>.

⁵⁸⁶ See, e.g., *Transmission Sys. Planning Performance Requirements for Extreme Weather*, Order No. 896, 88 FR 41262 (June 23, 2023), 183 FERC ¶ 61,191 (2023); *One-Time Info. Reports on Extreme Weather Vulnerability Assessments*, Order No. 897, 88 FR 41447 (June 27, 2023), 183 FERC ¶ 61,192 (2023).

⁵⁸¹ See New Jersey Commission Initial Comments at 10–11.

⁵⁸² See, e.g., Order No. 1000, 136 FERC ¶ 61,051 at P 12.

⁵⁸³ Alabama Commission Initial Comments at 7–8; Louisiana Commission Initial Comments at 12, 19–21; Potomac Economics Initial Comments at 3–4; Utah Division of Public Utilities Initial Comments at 2; Vistra Initial Comments at 11.

⁵⁸⁴ See ELCON Initial Comments at 9 (“ELCON has always believed that planning for disparate state energy priorities is at odds with market-driven, efficient, and cost-effective transmission planning.”).

236. We also disagree with Vistra's contention that Long-Term Regional Transmission Planning somehow will assign all, or a disproportionately high share, of interconnection-related network upgrade costs to load or undermine the incentives for generation developers to site new generation resources in ways that minimize transmission system upgrade costs. Rather, because transmission providers will now engage in Long-Term Regional Transmission Planning to identify, evaluate, and select more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs, Long-Term Regional Transmission Facilities will be planned in a more efficient and cost-effective manner than if transmission facilities meeting a narrower set of transmission needs were left to be identified through the generator interconnection process. Indeed, numerous commenters explain that the piecemeal expansion of the transmission system is highly inefficient and results in higher costs for transmission customers,⁵⁸⁷ in part because the costs of interconnection-related network upgrades ultimately are passed on to consumers.

237. We strike another careful balance in this final order. On the one hand, we recognize transmission providers' need for sufficient flexibility to implement Long-Term Regional Transmission Planning in their transmission planning regions to reflect regional differences, such as different market structures.⁵⁸⁸ On the other hand, we must ensure that transmission providers' regional transmission planning processes result in just and reasonable rates, which, as discussed above in the Overall Need for Reform section, necessitates that they plan on a sufficiently long-term, forward-looking, and comprehensive basis such that transmission providers are identifying, evaluating, and selecting more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs. We believe that the balance struck in the final order will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential and, thus, we reject requests for flexibility that exceeds that provided in this final order.

⁵⁸⁷ See, e.g., NYISO Initial Comments at 30; PIOs Initial Comments at 9–10.

⁵⁸⁸ The Commission also recognized the need for sufficient flexibility in regional transmission planning to reflect regional differences in Order No. 1000. See Order No. 1000, 136 FERC ¶ 61,051 at P 61.

238. In particular, we reject requests that, instead of requiring transmission providers to implement Long-Term Regional Transmission Planning in accordance with the requirements adopted in this final order, we set forth principles and objectives articulating our concerns with existing regional transmission planning processes and give transmission providers the flexibility to propose revisions to their processes to address those concerns.⁵⁸⁹ Having found existing regional transmission planning and cost allocation requirements to be unjust and unreasonable, we have an obligation under FPA section 206 to adopt reforms that remedy the deficiencies identified in this final order. We also believe that such an approach would fail to adequately address the deficiencies described above in the Overall Need for Reform section, namely that transmission providers are not currently required to: (1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs; and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs. We further believe that establishing requirements rather than principles will ensure a sufficiently robust process for Long-Term Regional Transmission Planning while providing sufficient clarity about that process to avert conflict among stakeholders, as noted by AEP.⁵⁹⁰

239. We also disagree with commenters that argue that this final order should apply to only RTO/ISO transmission planning regions. The Commission's existing regional transmission planning requirements, which, as described above in the Overall Need for Reform section, we find to be deficient, apply in RTO/ISO and non-RTO/ISO transmission planning regions alike; without the Long-Term Regional Transmission Planning Requirements adopted herein, transmission providers in both RTO/ISO and non-RTO/ISO transmission planning regions will continue to be at risk of undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Accordingly, while we acknowledge

⁵⁸⁹ ISO–NE Initial Comments at 20; ISO RTO Council Initial Comments at 4–5, 8–9; MISO Initial Comments at 22–23.

⁵⁹⁰ AEP Reply Comments at 2–4.

differences between RTO/ISO and non-RTO/ISO transmission planning regions, we find that transmission providers in all transmission planning regions must implement Long-Term Regional Transmission Planning as required in this final order to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. Additionally, we note that many of the requirements established in this final order provide for regional flexibility, including, but not limited to, the requirements to develop Long-Term Scenarios, determine which factors in each required category of factors do not affect Long-Term Transmission Needs and need not be considered, develop methods to measure the benefits of Long-Term Regional Transmission Facilities, design an evaluation process and selection criteria, and establish a Long-Term Regional Transmission Cost Allocation Method.

240. We acknowledge that certain transmission planning regions already conduct some regional transmission planning on a relatively forward-looking, proactive basis. We do not intend to undermine progress made in these transmission planning regions, and our goal is to set a floor, not a ceiling. We decline to prejudge whether any existing regional transmission planning process meets the requirements set forth in this final order and accordingly reject requests that we do so.⁵⁹¹ We note that, if a transmission provider believes that it participates in a regional transmission planning process that fulfills the requirements adopted in this final order, it may describe in its compliance filing how its process meets these requirements.

241. We expect Long-Term Regional Transmission Planning to enhance the existing regional transmission planning and cost allocation processes required by Order No. 1000. Except as set forth in this final order, we do not require that any transmission provider replace or otherwise make changes to its existing Order No. 1000-compliant regional transmission planning processes that plan for reliability or economic transmission needs, or the associated Order No. 1000-compliant regional cost allocation method(s). Transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.

⁵⁹¹ See, e.g., Ameren Initial Comments at 8.

242. We also do not alter the existing Order No. 1000 requirement to consider transmission needs driven by Public Policy Requirements in the regional transmission planning process. Instead, we clarify that we will deem transmission providers to be in compliance with this existing requirement by conducting Long-Term Regional Transmission Planning in accordance with the requirements set forth in this final order. As discussed below, we require transmission providers to incorporate a variety of factors into the development of Long-Term Scenarios, which include, among others, certain Federal, state, and local laws and regulations. Therefore, we find that transmission providers that implement Long-Term Regional Transmission Planning and satisfy the requirements set forth in this final order will comply with the requirement in Order No. 1000 to participate in a regional transmission planning process that considers, and has associated cost allocation provisions related to, transmission needs driven by Public Policy Requirements.

243. We understand—and acknowledge comments submitted in this proceeding explaining—that transmission providers in some transmission planning regions have developed processes to consider transmission needs driven by Public Policy Requirements through their regional transmission planning processes that they wish to retain.⁵⁹² In their filings made to comply with this final order, transmission providers may propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements. Transmission providers must nevertheless comply with the Long-Term Regional Transmission Planning requirements set forth in this final order, such that continued use of existing regional transmission planning and cost allocation processes related to transmission needs driven by Public Policy Requirements will not supplant transmission providers' obligation to comply with this final order. In their filing to comply with this final order, transmission providers that wish to continue to use some or all of their existing regional transmission planning and cost allocation processes to consider transmission needs driven by Public Policy Requirements must demonstrate that continued use of any

such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in this final order.

244. Similarly, we allow transmission providers to propose a regional transmission planning process that simultaneously plans for shorter-term reliability and economic transmission needs, as well as Long-Term Transmission Needs, as outlined in this final order, through a combined process. Transmission providers proposing to address all of these transmission needs in a single regional transmission planning process must demonstrate that the unified regional transmission planning process continues to comply with Order No. 1000, as well as with the Long-Term Regional Transmission Planning requirements set forth in this final order, by demonstrating that such a combined process is consistent with or superior to the requirements of both Order No. 1000 and this final order. However, in the case that the requirements of Order No. 1000 and this final order conflict, the requirements of this final order prevail, and transmission providers must demonstrate that their proposed regional transmission planning process is consistent with or superior to the applicable requirements in this final order.

245. We reject requests to require transmission providers to simultaneously plan for all such transmission needs through a single regional transmission planning process, however.⁵⁹³ We recognize that such a combined process has potential benefits and do not prohibit such an approach, but at this time we believe that the benefits of requiring such a combined process on a generic basis may be outweighed by the difficulty of transitioning to such a process from existing regional transmission planning processes. Therefore, we do not require in this final order that transmission providers plan for all reliability and economic transmission needs and Long-Term Transmission Needs through a single regional transmission planning process. Further, we believe that Long-Term Regional Transmission Planning, as set forth in this final order, meets many of the same objectives as would such a combined regional transmission planning process because, by identifying Long-Term Transmission Needs and considering a broad set of benefits when evaluating Long-Term Regional Transmission Facilities, the existing regional transmission planning processes for economic and reliability

needs may ultimately come to address only residual needs not already addressed through Long-Term Regional Transmission Planning.

246. With respect to the request by PIOs to mandate that the base cases used in Order No. 1000 regional transmission planning processes and Long-Term Scenarios in Long-Term Regional Transmission Planning be defined in the same process,⁵⁹⁴ we decline to adopt this proposal. The record is inadequate to assess the impact that such a requirement would have on existing Order No. 1000 regional transmission planning processes, and whether this proposal would work across the differing transmission planning processes in each transmission planning region. With respect to the proposals by Clean Energy Buyers, Cypress Creek, and Policy Integrity,⁵⁹⁵ these proposals were not among the proposals included in the NOPR and are beyond the scope of this proceeding, and therefore we decline to adopt them.

247. We also reject requests to incorporate local transmission planning into Long-Term Regional Transmission Planning specifically or regional transmission planning more generally,⁵⁹⁶ as well as requests to require transmission providers to evaluate and approve local transmission facilities in regional transmission planning.⁵⁹⁷ This final order sets forth requirements that will enhance the transparency of local transmission planning and examine opportunities for right-sizing in-kind replacements of existing transmission facilities, including local transmission facilities, but the Commission in the NOPR did not propose other changes to local transmission planning processes and therefore these requests are beyond the scope of this final order.

248. As discussed in detail below, we require transmission providers to satisfy specific requirements in implementing Long-Term Regional Transmission Planning, including requirements to: (1) use a transmission planning horizon of no less than 20 years into the future in developing Long-Term Scenarios; (2) reassess and revise those scenarios at least once every five years; (3) incorporate into the Long-Term Scenarios a set of Commission-identified categories of factors that give rise to Long-Term Transmission Needs;

⁵⁹⁴ PIOs Initial Comments at 44–46.

⁵⁹⁵ Clean Energy Buyers Initial Comments at 9–10; Cypress Creek Reply Comments at 10–12; Policy Integrity Supplemental Comments at 3.

⁵⁹⁶ AEE Initial Comments at 3, 38.

⁵⁹⁷ OMS Initial Comments at 16–17.

⁵⁹² CAISO Reply Comments at 17–18; New York Transco Initial Comments at 5.

⁵⁹³ See, e.g., ACEG Initial Comments at 30–31.

(4) develop a plausible and diverse set of at least three Long-Term Scenarios; (5) perform sensitivity analyses of uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area; and (6) use “best available data” in developing Long-Term Scenarios.

249. Before turning to these topics, however, we address two preliminary matters: the definition of Long-Term Regional Transmission Facility; and our jurisdiction to adopt these reforms.

b. Definition of Long-Term Regional Transmission Facility

250. We modify the NOPR proposal and define Long-Term Regional Transmission Facility for purposes of this final order as a regional transmission facility, as defined in Order No. 1000, that is identified as part of Long-Term Regional Transmission Planning to address Long-Term Transmission Needs.⁵⁹⁸ In so doing, we clarify that some Long-Term Regional Transmission Facilities may be selected in a regional transmission plan for purposes of cost allocation, while others may be considered for selection but not be selected.

251. This modification also clarifies that Long-Term Regional Transmission Facilities are a subset of regional transmission facilities as defined in Order No. 1000. Further, consistent with Order No. 1000,⁵⁹⁹ a selected Long-Term Regional Transmission Facility is a regional transmission facility that has been selected pursuant to a Commission-approved Long-Term Regional Transmission Planning process in a regional transmission plan for purposes of cost allocation because it is a more efficient or cost-effective solution to Long-Term Transmission Needs.

252. We disagree with PJM that Order No. 1000’s requirements related to regional transmission planning processes addressing transmission needs driven by reliability concerns or economic considerations will be unclear given the definition of Long-Term Regional Transmission Facility, and we find unpersuasive PJM’s contention that Long-Term Regional Transmission Planning will inadvertently cause the

re-litigation of aspects of those existing processes. If a regional transmission facility is selected in an existing Order No. 1000 regional transmission planning process, the rules of, as well as the regional cost allocation method for, that existing process apply to the selected regional transmission facility. If a Long-Term Regional Transmission Facility is selected in Long-Term Regional Transmission Planning, then the rules of, and the Long-Term Regional Cost Allocation Method for, Long-Term Regional Transmission Planning apply to that Long-Term Regional Transmission Facility.

c. Legal Authority To Adopt Reforms for Long-Term Regional Transmission Planning

253. We reaffirm our conclusion in the NOPR that we are acting within the Commission’s legal authority under FPA section 206 by requiring transmission providers to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning. The FPA grants the Commission authority over the transmission of electric energy in interstate commerce, which includes transmission on the interconnected national grids.⁶⁰⁰ FPA section 205 requires that the rates charged by any public utility in connection with such transmission—as well as the rules and regulations affecting such rates—be just and reasonable, and further requires that public utilities file with the Commission the practices affecting such rates.⁶⁰¹ Under FPA section 206, when the Commission determines that any rate or any practice affecting such rate is unjust, unreasonable, or unduly discriminatory or preferential—as we find above with respect to transmission planning practices—the Commission must determine the just and reasonable rate or practice to be followed.⁶⁰² Transmission planning and cost allocation processes are practices affecting the rates charged by public utilities in connection with the Commission-jurisdictional transmission of electric energy in interstate commerce.⁶⁰³ No commenter has claimed otherwise.

254. Despite this, a number of commenters claim that the specific transmission planning requirements we adopt in this final order infringe on the authority reserved to the states by FPA

section 201 or are otherwise barred by certain prudential or constitutional principles. As a threshold matter, we believe that commenters’ concerns with respect to our jurisdiction or authority to adopt this final order mainly arise from factual misunderstandings or mischaracterizations about what Long-Term Regional Transmission Planning will and will not require transmission providers to do. As explained above, this final order requires transmission providers in each transmission planning region to participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning and to conduct Long-Term Regional Transmission Planning in accordance with the requirements set forth in this final order. Transmission providers are required to identify Long-Term Transmission Needs, identify Long-Term Regional Transmission Facilities that meet such needs, measure the benefits of these Long-Term Regional Transmission Facilities, and evaluate these Long-Term Regional Transmission Facilities for potential selection. As such, this final order does not regulate, aim at, or otherwise attempt to influence integrated resource planning, the generation mix, decisions related to the siting and construction of transmission facilities or generation resources, or any other matters reserved to states under FPA section 201.

255. As discussed in the Introduction and Background section above, the requirements of this final order build upon more than a quarter century of significant actions taken by the Commission on transmission planning and cost allocation, beginning with the Commission’s initial open access reforms in Order No. 888. In 2007, the Commission issued Order No. 890 to address identified deficiencies in the *pro forma* OATT based on more than 10 years of experience since the issuance of Order No. 888. Most recently, in 2011, the Commission issued Order No. 1000, which required transmission providers to develop a regional transmission plan after evaluating whether regional transmission facilities may be more efficient or cost-effective than transmission facilities identified in local transmission planning processes and to consider transmission needs driven by Public Policy Requirements. These practices serve as the foundation for regional transmission planning, and this final order leaves them in place.

256. As described above, however, we have identified specific gaps in the Order No. 1000 framework—namely, that regional transmission planning practices do not perform a sufficiently

⁵⁹⁸ In the NOPR, the Commission proposed to define a Long-Term Regional Transmission Facility as a transmission facility identified as part of Long-Term Regional Transmission Planning and selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand. NOPR, 179 FERC ¶ 61,028 at P 252 n.398.

⁵⁹⁹ Order No. 1000, 136 FERC ¶ 61,051 at P 63.

⁶⁰⁰ *New York v. FERC*, 535 U.S. at 16–17 (citing 16 U.S.C. 824(b)).

⁶⁰¹ 16 U.S.C. 824d.

⁶⁰² 16 U.S.C. 824e.

⁶⁰³ See *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55–59; accord *Emera Me. v. FERC*, 854 F.3d at 673–74.

long-term assessment of transmission needs, adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs, or consider the broader set of benefits of regional transmission facilities. In this final order, we direct reforms to close these gaps without otherwise disturbing the regional transmission planning structure required by Order No. 1000, which was fully affirmed on appeal in the face of similar objections to those raised here.⁶⁰⁴

257. Critically, as in Order No. 1000, our focus continues to be on ensuring that Commission-jurisdictional regional transmission planning processes are just and reasonable and that, as a result of improvements to the regional transmission planning and cost allocation processes, Commission-jurisdictional rates remain just and reasonable.⁶⁰⁵ And, as in Order No. 1000, while the improvements to the regional transmission planning and cost allocation processes will ensure that potentially more efficient or cost-effective regional transmission facilities are evaluated for potential selection and have a cost allocation method available if they are selected, this order does not mandate development of any particular transmission facility.

258. Consistent with the regional transmission planning and cost allocation reforms adopted in Order No. 1000, and in response to commenters arguing otherwise,⁶⁰⁶ we affirm that this final order does not authorize or require any entity to adopt a particular siting plan for Long-Term Regional Transmission Facilities that transmission providers select; or to forego state-jurisdictional siting proceedings where they are necessary; or to begin construction on such Long-Term Regional Transmission Facilities. Even where transmission providers select a Long-Term Regional Transmission Facility, the relevant transmission developer typically must

secure a variety of other permits and authorizations before beginning to construct the facility, including those that are subject to state jurisdiction. Nothing in this final order changes otherwise applicable siting laws or requirements.

259. Similarly, this final order does not change existing mechanisms for cost-recovery through retail rates; authorize or require states or state commissions to change the laws or regulations that govern the conduct of integrated resource planning or request for proposal processes; authorize or require transmission providers or transmission developers to bypass any applicable state-regulated integrated resource planning or request for proposal processes; or authorize or require states or public utilities to adopt a different mix of generation resources than would otherwise be the case. Comments suggesting otherwise do not accurately represent the Commission's proposed requirements in the NOPR or the requirements adopted in this final order,⁶⁰⁷ which seeks to ensure that transmission providers plan for Long-Term Transmission Needs, however those needs arise.⁶⁰⁸

260. We disagree with Southern and SERTP Sponsors' characterization of Long-Term Regional Transmission Planning as a Commission-regulated integrated resource planning/request for proposal process.⁶⁰⁹ Similarly, comments that suggest that this final order intends to "revamp the energy grid's mix of generation resources writ large"⁶¹⁰ are incorrect. We understand these comments to argue that the Commission seeks reforms to regional transmission planning and cost allocation processes so that it can direct or influence investments toward particular resources, as would an entity

engaged in integrated resource planning. In this final order, the Commission neither aims to influence the resource mix, nor, as a practical matter, could the final order achieve such an outcome.

261. Instead, the final order merely requires transmission providers to account for observable changes affecting the transmission system. The final order neither directs those changes, nor does it require any entity, including a state, to approve changes to any subject within its jurisdiction. As with Order Nos. 890 and 1000, which built on the Commission's open access reforms in Order No. 888, this final order *responds* to changes in the electric industry that have arisen in the years since the Commission's last regulatory action related to transmission planning. As discussed above in the Overall Need for Reform section, this final order responds to evolving reliability concerns, including the increasing frequency of high-impact extreme weather events; changes in electricity demand, including significant load growth that is projected to increase in coming years; changes in supply, including Federal, federally-recognized Tribal, state, and local laws and policies that affect the future resource mix; changes in the economics of generation, transmission, and storage technologies; corporate, governmental, and utility commitments to rely on certain generation resources; and other factors as discussed in this final order.

262. We emphasize that these changes, which are affecting and will continue to drive transmission needs, are not within the Commission's control and, in many cases, are beyond the Commission's jurisdiction. We do not aim to influence these drivers of transmission needs through the requirements in this final order.⁶¹¹ However, the Commission has an obligation under the FPA to ensure that Commission-jurisdictional transmission rates remain just and reasonable, and we affirm—consistent with the Commission's actions in Order Nos. 890 and 1000—that the Commission has the requisite authority to account for the effects of these changes driving transmission needs in Commission-jurisdictional transmission planning processes.⁶¹²

263. We also emphasize, and no commenter contests, that this final order directly regulates transmission planning

⁶⁰⁴ See *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 55–64 (rejecting arguments that the requirement to engage in regional transmission planning, as prescribed in Order No. 1000, exceeded the Commission's jurisdiction under FPA section 206, interfered with traditional state authority reserved under FPA section 201, or improperly interpreted and applied FPA section 202(a)).

⁶⁰⁵ See *id.* at 63–64 (affirming that the Commission was acting within its jurisdiction because its planning mandate "relates wholly to electricity transmission, as opposed to electricity sales" and "is directed at ensuring the proper functioning of the interconnected grid spanning state lines").

⁶⁰⁶ Alabama Commission Initial Comments at 7; Kansas Ratepayer Advocates Reply Comments at 3; NARUC Initial Comments at 29; Nevada Commission Initial Comments at 2–3; Southern Initial Comments at 3–4, 7, 15–17; Southern Reply Comments at 6–7.

⁶⁰⁷ Alabama Commission Initial Comments at 3–4, 7–9; Kansas Ratepayer Advocates Reply Comments at 2; Louisiana Commission Initial Comments at 8–10, 27–28; Louisiana Commission Reply Comments at 14–15; Mississippi Commission Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring, at P 2); Nevada Commission Initial Comments at 2–3; SERTP Sponsors Initial Comments at 5, 16, 17 n.20, 19–20; SERTP Sponsors Reply Comments at 12–13; Southern Initial Comments at 3–4, 7–8, 12–13, 15–17, 23–24; Southern Reply Comments at 3, 6–7; Undersigned States Reply Comments at 2, 4–5, 8; Utah Commission Initial Comments at 7–9.

⁶⁰⁸ New Jersey Commission Reply Comments at 1–2.

⁶⁰⁹ SERTP Sponsors Initial Comments at 16–17; Southern Initial Comments at 3–4, 7, 15–17.

⁶¹⁰ Undersigned States Reply Comments at 4; see also Louisiana Commission Initial Comments at 6, 12–13 (arguing that the FPA does not allow the Commission to "enact[] sweeping energy policy changes that would have far-reaching, nationwide effects" or to favor one form of generation over another).

⁶¹¹ See *EPSA*, 577 U.S. 260 at 282 (citing *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 385 (2015)).

⁶¹² Cf. *EPSA*, 577 U.S. at 281–82 ("When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, 824(b) imposes no bar.").

and cost allocation processes, which are practices that affect the rates for the transmission of electric energy in interstate commerce. Importantly, it directly regulates *only* those practices, and it *does not* directly regulate any matter reserved to the states by FPA section 201. Moreover, in doing so, this final order is not aiming to *indirectly* regulate any matter reserved to the states by FPA section 201. Instead, our aim here is to improve on the Commission's existing transmission planning and cost allocation processes *for the express purpose* of addressing identified deficiencies with those processes.

264. As the U.S. Supreme Court has recognized, it is true that almost any action that the Commission takes with respect to regulating the practices affecting the rates for the transmission of or the wholesale sale of electric energy in interstate commerce will have “some effect, in either the short or long term” on matters reserved to the states’ jurisdiction.⁶¹³ But those effects, inevitable as they may be, are “of no legal consequence” to determining whether this final order infringes on the states’ authority under FPA section 201.⁶¹⁴ Instead, such effects are a “fact of economic life” for the electric industry, given Congress’s decision in the FPA to divide jurisdiction over the industry, including both generation and transmission, into spheres of Commission and state jurisdiction that are not “hermetically sealed” from one another.⁶¹⁵ Accordingly, Commission regulation of Commission-jurisdictional practices affecting transmission may “have natural consequences” for generation.⁶¹⁶ But, even where that happens, that does not defeat Federal jurisdiction.

265. Rather, as in *EPSA*, what matters is that this final order aims to regulate and, in fact, does regulate only practices that affect the transmission of electric energy in interstate commerce, which are squarely within the Commission’s jurisdiction under the FPA. As in Order Nos. 890⁶¹⁷ and 1000,⁶¹⁸ this final order aims to improve Commission-regulated transmission planning *processes*, in this instance by ensuring that they are sufficiently long-term, forward-looking, and comprehensive such that they are capable of identifying and meeting Long-Term Transmission Needs.⁶¹⁹

Thus, this final order ensures just and reasonable Commission-jurisdictional rates and practices by ensuring that transmission providers have adequate processes to identify Long-Term Transmission Needs and to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address those needs.

266. Moreover, as in *EPSA*, what also matters is that “every aspect of the [final order] happens exclusively” as part of a process that is subject to the Commission’s jurisdiction and governs exclusively how those processes work.⁶²⁰ In aiming to improve transmission planning processes, this final order does not require that transmission providers achieve any particular substantive *outcome* of those processes, including either the selection or construction of any specific transmission facilities. The final order patently does not aim to alter states’ or the Nation’s generation mix or otherwise regulate matters that are within state jurisdiction. Indeed, to the contrary, our rationale in this final order is “all about, and only about, improving” the relevant matters under the Commission’s jurisdiction.⁶²¹ Nor is it clear how, under commenters’ theory, the final order could be argued to regulate matters under states’ jurisdiction, given that the final order does not require investment in any particular transmission facilities, and could not, even indirectly, ensure investments in any particular set of generating facilities that may rely on such transmission facilities.

267. Despite some commenters’ claims,⁶²² nothing in this final order requires states to subsidize other states’ public policies and, indeed, this final order requires, consistent with long-established Commission and court precedent, that transmission customers within a transmission planning region need only pay costs that are “roughly commensurate” with the benefits that transmission providers estimate they will receive from a regional transmission facility.⁶²³ Thus, the final order ensures that transmission customers nationwide are not required

to pay for Long-Term Regional Transmission Facilities from which they do not benefit.

268. The reforms in the final order require greater transparency regarding the benefits that would result from the development of Long-Term Regional Transmission Facilities, but these reforms also continue to allow flexibility, as under Order No. 1000, for the transmission providers in each transmission planning region to determine the appropriate method for allocating to transmission customers the costs of any selected Long-Term Regional Transmission Facility. Rather than force transmission providers to adopt a particular cost allocation method that would necessarily result in customers in one state subsidizing the costs of customers in another state, as these commenters allege, the final order affords significant new opportunities for Relevant State Entities to inform the evaluation process, selection criteria, and cost allocation method adopted by the transmission providers in a transmission planning region. We believe that the requirements for greater transparency regarding the benefits of proposed transmission facilities, the increased opportunities for state engagement in evaluation, selection, and cost allocation, the flexibility for transmission providers in each transmission planning region to determine their own cost allocation methods, and the requirement that any cost allocation method must ensure costs are allocated in a manner that is at least roughly commensurate with estimated benefits provide robust assurance that the cost allocation methods ultimately proposed under the final order will not result in improper cost subsidization. Ultimately, the Commission must review and accept each cost allocation method proposed under the final order to ensure that it is just and reasonable and consistent with the final order’s requirements.

269. As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, this final order requires transmission providers to use and measure a set of seven required benefits to evaluate Long-Term Regional Transmission Facilities. The measurement of these benefits represents the value that the transmission providers expect a particular Long-Term Regional Transmission Facility to provide to transmission customers in the transmission planning region. As further discussed in the Regional Transmission Planning Cost Allocation section below, this final order requires transmission providers to provide a forum for

⁶¹³ *Id.* at 281 (emphasis added).

⁶¹⁴ *Id.*

⁶¹⁵ *Id.*

⁶¹⁶ *Id.*

⁶¹⁷ Order No. 890, 118 FERC ¶ 61,119 at P 3.

⁶¹⁸ Order No. 1000, 136 FERC ¶ 61,051 at P 12.

⁶¹⁹ *EPSA*, 577 U.S. at 281–83.

⁶²⁰ *Id.* at 282.

⁶²¹ *Id.* (citing *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. at 385).

⁶²² Alabama Commission Initial Comments at 8–9; Louisiana Commission Initial Comments at 6, 9–10; Mississippi Commission Reply Comments at 2–3; Ohio Commission Federal Advocate Initial Comments at 4–6; Ohio Consumers Reply Comments at 14.

⁶²³ See *Ill. Com. Comm’n v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014) (*ICC v. FERC III*); *ICC v. FERC I*, 576 F.3d at 477; *Sw. Power Pool, Inc.*, 182 FERC ¶ 61,141, at P 12 (2023).

Relevant State Entities to negotiate a cost allocation method and/or a process for determining future cost allocation methods for Long-Term Regional Transmission Facilities, which enables robust participation by those entities. Moreover, the cost allocation methods required by this final order are intended to ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits that a Long-Term Regional Transmission Facility provides to transmission customers.

270. The benefits this order requires to be used and measured—which provide an important source of transparency regarding any resulting allocation of costs to transmission customers—reflect objective, measurable changes in transmission system conditions, rather than achievement of state public policies. For example, even if a state's public policy is one driver of a Long-Term Transmission Need, these benefits of a Long-Term Regional Transmission Facility resolving that need are well understood and measurable, including, for example, reducing the cost of generating electricity by allowing for the increased dispatch of suppliers that have lower incremental costs of production, minimizing energy losses incurred in transmitting electricity, and lowering the number or duration of loss of load events. Transmission providers will evaluate Long-Term Regional Transmission Facilities for selection considering these benefits that these facilities would provide, and these benefits accrue to the transmission customers that fund their construction. In other words, under this final order, customers pay for a more reliable and economic transmission system as identified through open and transparent Long-Term Regional Transmission Planning, and any state's ratepayers only fund the construction of Long-Term Regional Transmission Facilities that provide them with such benefits that are at least roughly commensurate with the costs of those facilities.

271. We turn now to commenters' specific jurisdiction arguments. As an initial matter, we acknowledge that, in addition to granting authority to the Commission over the transmission of electric energy in interstate commerce, FPA section 201 also reserves certain authority to the states.⁶²⁴ As such, we

agree with Southern that Congress sought in enacting the FPA to ensure the "continued exercise of state power"⁶²⁵ over certain matters. However, the requirements in this final order respect and do not unlawfully infringe on state authority. Rather, as discussed above, the Commission is acting in an area squarely within its jurisdiction—transmission planning and cost allocation—by requiring transmission providers to engage in Long-Term Regional Transmission Planning to remedy deficiencies in the current transmission planning and cost allocation processes, which we conclude are unjust and unreasonable.

272. We acknowledge that Long-Term Regional Transmission Planning will affect matters that are within the states' jurisdiction. As stated, this is inevitable. Effective transmission planning necessarily involves taking into account assumptions about the generation resources that will be available, because transmission needs arise from the relative amounts, locations, and timing of supply (*i.e.*, generation) and of demand (*i.e.*, load); indeed, existing transmission planning processes also take into account these assumptions.⁶²⁶ Our action in this final order simply modifies the scope and duration of these assumptions to ensure that regional transmission planning processes are conducted on a sufficiently long-term, forward-looking, and comprehensive basis by requiring transmission providers to evaluate factors that give rise to Long-Term Transmission Needs.

273. Southern and SERTP Sponsors acknowledge that the NOPR proposed to require transmission providers to incorporate the results of state-sanctioned integrated resource planning as factors in developing Long-Term Scenarios, but they insist that Long-Term Regional Transmission Planning will intrude upon state authority if we do not require Long-Term Scenarios to be *limited* to those state-sanctioned resources.⁶²⁷ This assertion is incorrect for at least three reasons. First, the

had been beyond the reach of state power, but also the regulation of wholesale sales that had been *previously subject* to state regulation. More importantly, as discussed above, the FPA authorized Federal regulation of interstate *transmissions* as well as of interstate wholesale sales, and such transmissions were not of concern in *Attleboro*." (emphasis in original) (internal citations omitted)).

⁶²⁵ Southern Initial Comments at 16 (quoting *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. at 385).

⁶²⁶ See, e.g., Xcel Initial Comments at 13, 16 & n.26 (discussing generation resource assumptions made in existing Order No. 1000 regional transmission planning and cost allocation processes).

⁶²⁷ SERTP Sponsors Initial Comments at 15–17; Southern Initial Comments at 18–19.

public utilities whose integrated resource plans are approved by state commissions are not the only entities whose decisions may influence the development of generation resources within a particular transmission planning region. For example, a wide variety of private enterprises, publicly-owned utilities, and electric cooperatives have made commitments to fund the development of certain generation resources, and transmission providers may reasonably determine that these procurement decisions give rise to Long-Term Transmission Needs. Second, making generation resource assumptions for the purpose of performing transmission planning does not result in any legally-binding determination on a matter within a state's jurisdiction, let alone undermine a state's ability to ultimately decide what generation resources to build, and on what timetable.⁶²⁸ Third, as Southern and SERTP Sponsors concede,⁶²⁹ many existing integrated resource planning processes do not identify specific generation resources beyond a particular point in time. Other integrated resource planning processes may not result in a set of state-sanctioned generation resources and may instead serve merely as a guide for the relevant public utility.⁶³⁰ As a result, relying on such integrated resource planning processes exclusively to identify Long-Term Transmission Needs would fail to ensure that regional transmission planning processes are conducted on a sufficiently long-term, forward-looking, and comprehensive basis and therefore would fail to ensure just and reasonable Commission

⁶²⁸ We disagree with Southern's and SERTP Sponsors' contention that the inclusion of such non-binding assumptions about generation resources in transmission planning will "bias" subsequent state resource decisions. See Southern Initial Comments at 19; SERTP Sponsors Initial Comments at 17 n.20. As Kentucky Commission Chair Chandler argues, the NOPR's reforms do not foreclose states' decision making on generation. Kentucky Commission Chair Chandler Reply Comments at 3. We also disagree with North Carolina Commission and Staff's contention that merely requiring transmission providers to use and measure production cost savings in evaluating Long-Term Regional Transmission Facilities "could conflict with state-jurisdictional resource decisions." North Carolina Commission and Staff Initial Comments at 7. If nothing else, Long-Term Regional Transmission Planning will provide public utilities and state commissions the opportunity to develop longer-term, forward-looking, robust assessments that can inform future decision making.

⁶²⁹ SERTP Sponsors Initial Comments at 16; Southern Initial Comments at 19.

⁶³⁰ See, e.g., SREA Reply Comments at 2–3 (arguing, in response to Alabama Commission, that Alabama has no formal integrated resource plan process upon which the Commission could encroach).

⁶²⁴ See 16 U.S.C. 824(a)–(b)(1); *New York v. FERC*, 535 U.S. at 20–21 ("It is, however, perfectly clear that the original FPA did a good deal more than close the gap in state power identified in [*Pub. Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83 (1927)] (*Attleboro*)). The FPA authorized Federal regulation not only of wholesale sales that

jurisdictional-rates. To be clear, we are not in this final order attempting to denigrate or diminish the importance of integrated resource planning. Rather, in the context of Long-Term Regional Transmission Planning, integrated resource planning is reasonably considered one of several categories of factors used to develop Long-Term Scenarios and identify Long-Term Transmission Needs.

274. In that light, Southern's and SERTP Sponsors' argument—that we should limit transmission providers to state-approved resources and prohibit non-binding assumptions about the resource mix and demand—does not safeguard but in fact subverts the FPA's division between Federal and state authority. As stated above, were we to require that transmission providers limit their assumptions to only state-sanctioned generation resources, we would be requiring transmission providers to ignore many of the factors that, as demonstrated by this record, transmission providers must reasonably consider to plan on a sufficiently long-term, forward-looking, and comprehensive basis. Instead, it is within our jurisdiction to determine the factors that transmission providers must incorporate in order to identify Long-Term Transmission Needs.

275. Commenters' arguments that the final order would not withstand judicial scrutiny under the “major questions doctrine” are similarly unfounded. For example, some commenters appear to misinterpret *West Virginia v. EPA* as standing for the proposition that “the nation's energy policy and generation mix is a ‘major question’ and that an agency must have direct authorization from Congress to assert jurisdiction” over these matters.⁶³¹ As an initial matter, as noted above, the aim of this final order is not to influence the generation mix or energy policy more broadly, but to ensure that Commission-jurisdictional transmission providers are planning for Long-Term Transmission Needs in a manner that is just and reasonable and results in just and reasonable Commission-jurisdictional rates.

276. In any case, the Court did not determine that energy policy and the mix of generation resources are *in every instance* a major question. Instead, in *West Virginia v. EPA*, the U.S. Supreme Court considered a specific agency action in light of a specific statutory

provision and concluded that the Environmental Protection Agency's (EPA) exercise of authority was a “major question” based on a variety of factors specific to that context—including whether the EPA's administrative action was a “transformative” expansion of its power, whether the EPA had relevant technical and policy expertise, whether the relevant statutory provision was “ancillary” to the broader statutory construct, and whether the EPA's administrative action implicated significant economic and political questions.⁶³²

277. Commenters have not attempted a similar analysis of whether courts should construe this final order as a “major question,”⁶³³ and we find that their contentions that courts ought to do so are based on the factual mischaracterizations discussed above. In any event, this final order neither transforms nor expands the Commission's authority; it merely applies existing authority, based on the Commission's expertise and experience, to identify and remedy deficiencies in existing regional transmission planning and cost allocation processes.⁶³⁴ As with Order Nos. 890 and 1000, the Commission is promulgating a final order pursuant to FPA section 206 to address those deficiencies in order to ensure that transmission planning practices, a subject long-regulated by the Commission and well within its area of expertise, remain just and reasonable and not unduly discriminatory or preferential. To that end, this final order requires further reforms to regional transmission planning and cost allocation processes so that they are sufficiently long-term, forward-looking, and comprehensive. And while the transmission planning required in this final order may be more forward-looking, long-term, and comprehensive than the status quo, as a matter of the Commission's jurisdiction, it is fundamentally no different than the regional transmission planning already required by the Commission and upheld by appellate courts.⁶³⁵ In short, the differences in transmission planning required by this final order represent

differences in degree, not kind, from the Commission's longstanding regulations. As such, they are a far cry from the “transformative expansion” of the EPA's authority on which the Court relied in *West Virginia v. EPA* to find that the issue presented therein represented a major question not delegated to the agency to decide.

278. Just as it is clear that incremental improvements to practices that the courts have already determined fall squarely within the Commission's jurisdiction do not constitute a “transformative expansion” or “extraordinary grant” of regulatory authority to which the major questions doctrine may apply, so too is it clear that the other ancillary factors cited by the Court are similarly inapplicable. The final order's incremental process improvements, while necessary to ensure just and reasonable Commission-jurisdictional rates, do not have the “vast economic and political significance” that would implicate the major questions doctrine.⁶³⁶ The Commission's regulation of interstate transmission rates will have an effect on billions of dollars in customer charges and, in that generic sense, is of political interest to many. The incremental process improvements required by the final order, however, do not fundamentally change the economic or political stakes of ensuring that Commission-jurisdictional rates remain just and reasonable.

279. Likewise, the Commission's continued assertion of authority over regional transmission planning and cost allocation processes does not resemble the EPA's assertion of authority related to the electric system that the Court found to be beyond that agency's expertise.⁶³⁷ Here, the Commission undisputedly bears the relevant expertise over the interstate transmission system.⁶³⁸ Nor does the Commission rely on a “backwater” statutory provision to achieve its reforms.⁶³⁹ The Commission relies on FPA sections 205 and 206, which the Court has held “unambiguously authorize[]” the Commission to assert jurisdiction over interstate

⁶³² *West Virginia v. EPA*, 597 U.S. at 710, 724–725, 729, 731–32; see also *Biden v. Nebraska*, 143 S. Ct. 2355, 2372–2374 (2023) (applying *West Virginia v. EPA*'s mode of analysis).

⁶³³ See Harvard ELI and Policy Integrity Supplemental Comments at 2 (arguing that Undersigned States, for example, “overlook key requirements of the major questions doctrine”).
⁶³⁴ See, e.g., *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 68–69. Cf. *PJM Power Providers Grp. v. FERC*, 88 F.4th at 274.

⁶³⁵ See, e.g., *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 48–49; see also Harvard ELI and Policy Integrity Supplemental Comments at 4–7.

⁶³⁶ *West Virginia v. EPA*, 597 U.S. at 735 (J. Gorsuch, concurring).

⁶³⁷ *West Virginia v. EPA*, 597 U.S. at 729 (finding relevant that EPA itself admitted it lacked expertise to project “system-wide trends in areas such as electricity transmission, distribution, and storage”).

⁶³⁸ Cf. *Amerada Hess Pipeline Corp. v. FERC*, 117 F.3d 596, 600–01 (D.C. Cir. 1997) (“[The Federal Energy Regulatory Commission] is entrusted with administering the regulations relating to oil pipelines and has an expertise in the field based on that jurisdiction.” (emphasis added)).

⁶³⁹ *West Virginia v. EPA*, 597 U.S. at 729.

⁶³¹ SERTP Sponsors Initial Comments at 17–18; Southern Initial Comments at 20; see also Undersigned States Reply Comments at 3 (“National-scale energy grid regulation is a ‘major question’ because of the massive economic consequences involved in such regulation.”).

transmission⁶⁴⁰ and extends an authority—indeed, a duty—to ensure that the practices directly affecting such rates are just and reasonable.⁶⁴¹ This provision was not ancillary to the statutory scheme but, rather, central to Congress' aim to ensure that the Commission possessed adequate authority to regulate interstate transmission beyond the reach of state power.⁶⁴² Finally, commenters do not point to Congress's "conspicuous[] and repeated[]" rejection of legislation that would enact reforms similar to those adopted in the final order.⁶⁴³

280. We also disagree with Undersigned States' legal claim that allowing "one [s]tate [to] effectively require other [s]tates to subsidize their own vision of what resources should be used in electricity generation" would violate the Constitution's "equal sovereignty doctrine."⁶⁴⁴ As discussed above, the final order categorically does not require states to subsidize other states' public policies or generation decisions. To the contrary, consistent with the cost causation principle, this final order requires customers to pay for a share of the costs of new Long-Term Regional Transmission Facilities only to the extent that *they* benefit from those facilities and, even then, any share they pay for must be roughly commensurate with the benefits they receive.⁶⁴⁵

281. Moreover, according to Undersigned States, the equal sovereignty doctrine dictates that the Nation "is a union of [s]tates, equal in power, dignity and authority, each competent to exert that residuum of sovereignty not delegated to the United States by the Constitution itself."⁶⁴⁶ But, "neither the Supreme Court nor any other court has ever applied that principle as a limit on the Commerce Clause or other Article I powers."⁶⁴⁷ Instead, Courts have found that "the Constitution does not contain any textual provision suggesting an equal sovereignty limit on Congress's Article I powers generally or on the Commerce

Clause in particular."⁶⁴⁸ As relevant here, pursuant to the Constitution's Commerce Clause,⁶⁴⁹ Congress duly enacted the FPA, which in turn empowers the Commission to regulate the rates and practices affecting rates for the transmission of electricity in interstate commerce.⁶⁵⁰ Under the FPA, the Commission is "unambiguously authorize[d] . . . to take state policies into account to the extent that such policies affect [the Commission's] statutorily prescribed area of focus"⁶⁵¹

282. The nature of the interconnected transmission system is such that states naturally affect one another in pursuing policies available to them while exercising the authority reserved to them under FPA section 201.⁶⁵² For the reasons explained in this final order, we conclude that transmission providers must participate in a regional transmission planning process that includes Long-Term Regional Transmission Planning, and we find that transmission providers must have the opportunity to select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. Our role within our Federal system is not to "unreasonably interfere with" nor to "pass judgement on state and local policies and objectives,"⁶⁵³ including where such policies and objectives have incidental interstate effects.⁶⁵⁴ Nor need we, because even if one state's public policy is a driver of a Long-Term Transmission Need, the costs of a Long-Term Regional Transmission Facility that transmission providers select will be allocated to

transmission customers only to the extent that they benefit from that facility and only to a degree that is at least roughly commensurate with the benefits that facility provides to them. That approach is consistent with Commission precedent and commenters have not demonstrated that this framework results in impermissible cross-subsidization among states.⁶⁵⁵

283. Finally, in response to NRECA's request, we confirm that the final order is consistent with the Commission's obligation under FPA section 217(b)(4). As articulated in *South Carolina Public Service Authority v. FERC*, FPA section 217(b)(4) requires the Commission to "facilitate the planning of a reliable grid," and we do so by "seek[ing] to ensure that adequate transmission capacity is built to allow load-serving entities to meet their service obligations."⁶⁵⁶ This final order seeks to ensure precisely the same goal, and it therefore satisfies the Commission's obligation under FPA section 217(b)(4).

B. Development of Long-Term Scenarios

1. NOPR Proposal

284. In the NOPR, the Commission proposed to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning. The Commission proposed to define Long-Term Scenarios as a tool to identify the transmission planning region's needs driven by changes in the resource mix and demand—and enable the evaluation of transmission facilities to meet such transmission needs—across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon. The Commission explained that a scenario is a hypothetical sequence of events that includes assumptions used to forecast transmission needs. The Commission also stated that assumptions used to forecast transmission needs driven by

⁶⁴⁰ *Id.* at *16.

⁶⁴¹ U.S. Const. art. 1, 8.

⁶⁴² 16 U.S.C. 824d.

⁶⁴³ *PJM Power Providers Grp. v. FERC*, 88 F.4th at 275; see also *Elec. Power Supply Ass'n v. Star*, 904 F.3d at 524 (approving of the Commission's decision to take state zero-emissions credit systems like that in Illinois "as givens and set out to make the best of the situation [these systems] produce").

⁶⁴⁴ See *Elec. Power Supply Ass'n v. Star*, 904 F.3d at 524 (describing the effects on interstate sales resulting from states' exercise of powers reserved to them under FPA section 201 as "an inevitable consequence of a system in which power is shared between state and national governments" (citing *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 164 (2016))).

⁶⁴⁵ *N.J. Bd. Pub. Utils. v. FERC*, 744 F.3d 74, 98 n.24 (3rd Cir. 2014) (quoting *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 3 (2011)); see also *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080, at P 186 (2024) (rejecting an argument that the Commission was required to determine whether state-sponsored resources were providing disproportionate benefits to other states in the form of lower capacity market prices).

⁶⁴⁶ See *Coal. for Competitive Elec. v. Zibelman*, 906 F.3d 41, 56 (2d Cir. 2018) (collecting Commission orders sanctioning state-jurisdictional programs incidentally affecting wholesale markets).

⁶⁴⁷ For example, PJM incorporates transmission needs driven by Public Policy Requirements into the assumptions stage of its regional transmission planning process to identify needed reliability and economic regional transmission facilities for potential selection and cost allocation, rather than through a separate and distinct process to identify and allocate the costs of transmission facilities selected to address transmission needs driven by Public Policy Requirements. The Commission found PJM's approach complied with the requirement in Order No. 1000 to consider transmission needs driven by Public Policy Requirements in regional transmission planning and cost allocation processes. *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at PP 109–120 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128, at PP 66–71 (2014).

⁶⁴⁸ 762 F.3d at 90.

⁶⁴⁰ *New York v. FERC*, 535 U.S. at 19.

⁶⁴¹ *EPSA*, 577 U.S. at 277.

⁶⁴² *New York v. FERC*, 535 U.S. at 20–21 (discussing enactment of FPA in 1935 as a response to *Attleboro*).

⁶⁴³ *West Virginia v. EPA*, 597 U.S. at 745 (J. Gorsuch, concurring).

⁶⁴⁴ Undersigned States Reply Comments at 5–6.

⁶⁴⁵ See *supra* note 623 and accompanying discussion.

⁶⁴⁶ Undersigned States Reply Comments at 5 (citing *Coyle v. Smith*, 221 U.S. at 567). But see *Ohio v. EPA*, 2024 WL 1515001, at *15 (D.C. Cir. Apr. 9, 2024) (holding that "[t]he equal footing cases," like *Coyle v. Smith*, "do not directly apply either outside of the admission context or to Article I powers like the Commerce Clause.").

⁶⁴⁷ *Ohio v. EPA*, 2024 WL 1515001 at *13.

changes in the resource mix and demand include: forecasts of the level and pattern (*i.e.*, hourly and seasonal variability) of future electricity demand; the quantity, location, and type of resource additions and retirements; and other relevant forecasts about the electric power system that are used as inputs to the transmission model and determine the need for new transmission facilities over the transmission planning horizon. In addition, the Commission noted that other relevant assumptions might include forecasts for natural gas prices, increasing outage trends due to extreme weather and climatic trends, and other future events.

285. The Commission also proposed in the NOPR to require that transmission providers use Long-Term Scenarios to evaluate potential regional transmission facilities needed to meet transmission needs driven by changes in the resource mix and demand to identify the more efficient or cost-effective regional transmission facilities.⁶⁵⁷

2. Comments

a. General Comments

286. Of the commenters specifically addressing the proposal to require Long-Term Scenarios in Long-Term Regional Transmission Planning, the majority support scenario-based planning.⁶⁵⁸ Clean Energy Buyers state that Long-Term Scenarios are critical to Long-Term Regional Transmission Planning because its success will depend on the quality of forecasting.⁶⁵⁹ Form Energy states that long-term scenario review will ensure that transmission upgrades address future needs in a cost-effective and environmentally friendly manner.⁶⁶⁰ LADWP asserts that Long-

Term Scenarios are critical to developing an effective transmission system that ensures reliability, while also providing flexibility to support the delivery of renewable energy.⁶⁶¹ NARUC states that Long-Term Scenarios are a flexible planning tool for addressing the uncertainty involved in identifying transmission needs driven by changes in the resource mix and demand and that using them will ensure that transmission providers adequately assess the potential benefits of regional transmission facilities.⁶⁶²

287. Southeast PIOs claim that Long-Term Scenarios are essential to improving current transmission planning processes in the Southeast.⁶⁶³ SREA argues that Long-Term Regional Transmission Planning is not occurring in MISO South and states that scenario planning is contentious but necessary.⁶⁶⁴

288. California Energy Commission requests that the Commission clarify that transmission providers may rely on scenarios developed by other agencies, as currently CAISO relies on analyses conducted by California Energy Commission and California Commission.⁶⁶⁵ Relatedly, New York Commission and NYSEDA and ISO-NE highlight the importance of state-led identification of public policy needs and their impact on scenario assumptions.⁶⁶⁶ New York Commission and NYSEDA state that, especially in a single-state RTO/ISO like NYISO, the state should be afforded a central role in determining the scenarios to be studied.⁶⁶⁷ ISO-NE also believes that reliance on states is consistent with prior Commission orders permitting transmission providers to rely on a committee of state regulators to identify transmission needs driven by Public Policy Requirements.⁶⁶⁸

289. PJM States suggest that the Commission's proposal for state involvement in the development of Long-Term Scenarios could be interpreted as more limited than its proposal for state involvement with respect to Long-Term Regional Cost Allocation and ask that the Commission clarify that retail regulators have a

primary role in both. PJM States warn that, if a retail regulator disagrees with the scenarios or benefits metrics used to select a transmission project, it is unlikely to receive regulatory approval.⁶⁶⁹

290. Cypress Creek asserts that the Commission should require the use of a defined and standardized set of baseline assumptions to ensure that scenario projections are realistic, and that deviation should only be allowed if the proposal is consistent with or superior to the *pro forma*.⁶⁷⁰

291. Concerned Scientists state that the Commission should reject comments arguing that uncertainty prohibits scenario-based planning, and instead endeavor to create a transmission planning process that properly acknowledges and addresses that uncertainty. Concerned Scientists state that uncertainty does not prohibit long-term transmission planning but rather necessitates the evaluation of multiple plausible scenarios to identify investments that will perform well over a variety of possible future conditions. Concerned Scientists explain that, just as utilities and generator developers do not shy away from an uncertain future when building new generation resources, transmission investments should also be informed by, but not avoided due to, future uncertainty. Concerned Scientists state that the Commission's proposed Long-Term Scenarios requirements are a reasonable minimum for responsible transmission planning.⁶⁷¹

292. Other commenters support the NOPR proposal to require Long-Term Scenarios in transmission planning but have reservations.⁶⁷² Many of these commenters argue that the NOPR is too prescriptive and ask for greater flexibility so that the Long-Term Scenario planning already occurring in their respective transmission planning region will comply with any final order.⁶⁷³ For example, OMS points to such flexibility as key to the success of MISO's long-term transmission planning

⁶⁵⁷ NOPR, 179 FERC ¶ 61,028 at P 84.

⁶⁵⁸ See ACEG Initial Comments at 6; AEP Initial Comments at 7–8; Amazon Initial Comments at 2–3; BP Initial Comments at 4; California Commission Initial Comments at 1–2, 5–6, 21; California Energy Commission Initial Comments at 1–2; City of New York Initial Comments at 7; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 11; Duke Initial Comments at 10; Eversource Initial Comments at 10; Exelon Initial Comments at 5; Form Energy Initial Comments at 2–3; GridLab Initial Comments at 10; Handy Law Initial Comments at 9–10; Indicated PJM TOs Initial Comments at 7–8; LADWP Initial Comments at 2; NARUC Initial Comments at 4; National Grid Initial Comments at 10–11; PIOs Initial Comments at 14; PPL Initial Comments at 4; SEIA Initial Comments at 4–5; Southeast PIOs Initial Comments at 42; SREA Initial Comments at 39; State Agencies Initial Comments at 14; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments); US Climate Alliance Initial Comments at 2; WE ACT Initial Comments at 3; WIRES Initial Comments at 6.

⁶⁵⁹ Clean Energy Buyers Initial Comments at 11.

⁶⁶⁰ Form Energy Initial Comments at 3.

⁶⁶¹ LADWP Initial Comments at 2.

⁶⁶² NARUC Initial Comments at 4.

⁶⁶³ Southeast PIOs Initial Comments at 42, 46.

⁶⁶⁴ SREA Initial Comments at 39–41.

⁶⁶⁵ California Energy Commission Initial Comments at 2.

⁶⁶⁶ New York Commission and NYSEDA Initial Comments at 7; ISO-NE Initial Comments at 25–26.

⁶⁶⁷ New York Commission and NYSEDA Initial Comments at 8.

⁶⁶⁸ ISO-NE Initial Comments at 25 (citing *ISO New England Inc.*, 143 FERC ¶ 61,150, at P 108 (2013)).

⁶⁶⁹ PJM States Initial Comments at 3–4 (citing NOPR, 179 FERC ¶ 61,028 at P 245).

⁶⁷⁰ Cypress Creek Reply Comments at 5–8.

⁶⁷¹ Concerned Scientists Reply Comments at 18–19.

⁶⁷² Ameren Initial Comments at 7–8; American Municipal Power Initial Comments at 7; APPA Initial Comments at 25; CAISO Initial Comments at 21; Chemistry Council Initial Comments at 5; Michigan Commission Initial Comments at 4–5; MISO TOs Initial Comments at 15–17; Omaha Public Power Initial Comments at 3–4; OMS Initial Comments at 3–5; PJM Initial Comments at 54.

⁶⁷³ CAISO Initial Comments at 21; Michigan Commission Initial Comments at 4–5; MISO TOs Initial Comments at 15–16; OMS Initial Comments at 3–4.

processes.⁶⁷⁴ SERTP Sponsors argue that the Commission should not make Long-Term Scenarios even more prescriptive because such an approach would likely result in litigation and delay.⁶⁷⁵

293. American Municipal Power believes that transmission providers should conduct Long-Term Scenarios in a highly collaborative way with the full and active participation of all stakeholders.⁶⁷⁶ Similarly, Six Cities recommend that Long-Term Scenarios be coordinated between state and local regulatory authorities to reflect varying policies. Six Cities recommend that, in CAISO, Long-Term Scenarios should consider the procurement choices of non-jurisdictional utilities, such as Six Cities, as well as policy portfolios provided by California Commission.⁶⁷⁷

294. Some commenters oppose the NOPR proposal to require Long-Term Scenarios in Long-Term Regional Transmission Planning.⁶⁷⁸ Dominion argues for maximum flexibility for planning assumptions to support reliable and affordable transmission service for customers.⁶⁷⁹ Idaho Commission states that any prescription for scenario analysis should be supported by clear evidence of a deficiency.⁶⁸⁰ Instead of specific scenario planning requirements, Nebraska Commission states that the Commission should provide general guidelines and as much flexibility as possible to transmission providers, who—along with state regulatory officials—are best situated to evaluate the needs of each transmission planning region.⁶⁸¹

295. Potomac Economics questions the NOPR's proposal to require Long-Term Scenarios, stating that it will force RTOs/ISOs to plan and commit to sizable transmission investment costs based on uncertain factors and unreasonable speculation on factors such as the location of future generation, retirements, grid enhancing technologies, and transmission reconfiguration options.⁶⁸² Potomac Economics also questions the usefulness of Long-Term Scenarios, asserting that future congestion patterns will be

increasingly uncertain given that the higher penetration of intermittent resources will cause larger fluctuations in transmission flows, making it more difficult to accurately estimate the benefits of transmission upgrades.⁶⁸³ Potomac Economics argues that many of the most beneficial transmission upgrades address very specific constraints, are smaller in size, can be difficult to identify in advance, and can be very sensitive to modest changes in generation and load.⁶⁸⁴

b. Applying Scenario Planning to Reliability and Economic Planning

296. California Commission and City of New York assert that the Commission should require the use of Long-Term Scenarios in all transmission planning processes—not just Long-Term Regional Transmission Planning.⁶⁸⁵ City of New York argues that such a requirement would enable consideration of a broad range of potential future system conditions across multiple planning categories.⁶⁸⁶ Similarly, NYISO states that the final order should authorize, but not require, the use of multiple alternative scenarios in existing transmission planning processes. NYISO states that doing so would enhance its ability to anticipate and solicit more efficient, holistic transmission solutions, which would support system reliability and resilience.⁶⁸⁷

297. In contrast, certain commenters oppose requiring transmission providers to incorporate some form of scenario analysis into their existing reliability and economic regional transmission planning processes.⁶⁸⁸ Duke contends that the Commission should avoid disrupting existing regional transmission planning processes that work well.⁶⁸⁹ MISO notes that, while this type of scenario-based planning has been applied to economic transmission planning processes and could be applied to existing reliability transmission planning processes, such application should be flexible and tailored to the unique needs of each transmission provider, adding that scenario-based planning requires considerable time and resources.⁶⁹⁰

3. Commission Determination

298. We adopt, with modification, the NOPR proposals to require transmission providers in each transmission planning region to (1) develop and use Long-Term Scenarios as part of Long-Term Regional Transmission Planning and (2) use those Long-Term Scenarios to identify and evaluate Long-Term Regional Transmission Facilities needed to meet Long-Term Transmission Needs. As further explained in subsequent sections of this final order, we find that these requirements regarding the development and use of Long-Term Scenarios in Long-Term Regional Transmission Planning strike a reasonable balance between ensuring that Long-Term Regional Transmission Planning reasonably identifies Long-Term Transmission Needs over a sufficiently long-term, forward-looking transmission planning horizon and providing sufficient flexibility for transmission providers to develop and use Long-Term Scenarios in a way that reflects the unique characteristics of their respective transmission planning regions.

299. We first address the definition of Long-Term Transmission Needs. For purposes of this final order, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning by, among other things and as discussed in this final order, running scenarios and considering the enumerated categories of factors. As explained in the NOPR, the drivers of transmission needs are diverse and include, but are not limited to, evolving reliability concerns, changes in the resource mix, and changes in demand. For example, as identified in the NOPR, reliability concerns giving rise to Long-Term Transmission Needs include, among other things, the increasing frequency of high-impact extreme weather events, the increasing reliance by transmission system operators on regional integration and coordination to reliably serve load, the operational challenges created by the increasing share of variable resources entering the resource mix, and changes in electric demand patterns such as shifts in load profiles caused by, for example, the emergence of large loads associated with evolving industrial and commercial needs such as the growth in data centers, and increased electrification of energy end uses.⁶⁹¹

300. In the NOPR, the Commission referred to transmission needs identified through Long-Term Regional Transmission Planning largely as needs

⁶⁷⁴ OMS Initial Comments at 4–5.

⁶⁷⁵ SERTP Sponsors Reply Comments at 13–14.

⁶⁷⁶ American Municipal Power Initial Comments at 7.

⁶⁷⁷ Six Cities Initial Comments at 4.

⁶⁷⁸ Dominion Initial Comments at 10; Idaho Commission Initial Comments at 3; Nebraska Commission Initial Comments at 3; Ohio Consumers Initial Comments at 2, 5; Potomac Economics Initial Comments at 2.

⁶⁷⁹ Dominion Initial Comments at 10–12.

⁶⁸⁰ Idaho Commission Initial Comments at 3.

⁶⁸¹ Nebraska Commission Initial Comments at 3.

⁶⁸² Potomac Economics Initial Comments at 2, 4.

⁶⁸³ *Id.* at 2.

⁶⁸⁴ *Id.* at 3.

⁶⁸⁵ California Commission Initial Comments at 22–24; City of New York Initial Comments at 7.

⁶⁸⁶ City of New York Initial Comments at 7.

⁶⁸⁷ NYISO Initial Comments at 14–15.

⁶⁸⁸ Duke Initial Comments at 2, 10–11; Eversource Initial Comments at 19; MISO Initial Comments at 32; NESCOE Initial Comments at 23; PJM Initial Comments at 54–56.

⁶⁸⁹ Duke Initial Comments at 2, 10–11.

⁶⁹⁰ MISO Initial Comments at 32.

⁶⁹¹ See NOPR, 179 FERC ¶ 61,028 at PP 45, 51.

driven by changes in the resource mix and demand.⁶⁹² Nevertheless, we agree with commenters who correctly note that there are additional drivers of Long-Term Transmission Needs,⁶⁹³ and, as noted above, the Commission itself contemplated in the NOPR that Long-Term Regional Transmission Planning would consider drivers beyond those tied directly to changes in supply and demand. We therefore clarify that, although changes in the resource mix and demand are important drivers of Long-Term Transmission Needs, they represent only a subset of such drivers. In addition, we note that Long-Term Transmission Needs are similar in kind to transmission needs identified through existing regional transmission planning processes established under Order No. 1000. Where Long-Term Transmission Needs differ is their identification through the long-term, forward-looking, and more comprehensive regional transmission planning and cost allocation processes established in this final order. Accordingly, in this final order, we refer to the transmission needs that are identified through Long-Term Regional Transmission Planning as Long-Term Transmission Needs. The identification of Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to potentially meet those needs is accomplished through the use of Long-Term Scenarios in Long-Term Regional Transmission Planning.

301. As discussed in the Requirement for Transmission Providers to Use a Set of Seven Required Benefits section of this final order, we require transmission providers to measure and use a set of seven required benefits in Long-Term Regional Transmission Planning. Transmission providers must use this same set of benefits to help to inform their identification of Long-Term

Transmission Needs. For example, in this final order we require transmission providers to measure and use production cost savings in Long-Term Regional Transmission Planning. As such, when transmission providers are working to identify Long-Term Transmission Needs, areas of significant congestion on the transmission system—where Long-Term Regional Transmission Facilities could reduce congestion and in turn facilitate production cost savings—may indicate a Long-Term Transmission Need.

302. We adopt the definition of Long-Term Scenarios proposed in the NOPR,⁶⁹⁴ with modification. We define Long-Term Scenarios as scenarios that incorporate various assumptions using best available data inputs about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs. We make this modification to clarify the intent of the definition proposed in the NOPR, rather than modify the definition in substance.

303. Certain commenters assert that the Commission should not require transmission providers to develop Long-Term Scenarios due to the inherent uncertainty of forecasting future transmission needs over a long transmission planning horizon. We acknowledge the inherent uncertainty involved in planning to meet Long-Term Transmission Needs. However, we believe that such uncertainty is mitigated by using Long-Term Scenarios themselves, as noted by Concerned Scientists and NARUC.⁶⁹⁵ Scenario planning allows transmission providers to evaluate whether Long-Term Regional Transmission Facilities are beneficial in more than one scenario. Transmission providers may also examine whether Long-Term Transmission Needs appear in one or more scenarios. Scenario planning also allows transmission providers to consider a broader range of future circumstances and be better prepared for changes in the electric

power system.⁶⁹⁶ Finally, transmission providers may use scenario planning to determine whether identified Long-Term Regional Transmission Facilities provide sufficient benefits across more than one scenario when considering whether to select such facilities, as also noted by NARUC.⁶⁹⁷ Moreover, we adopt requirements for Long-Term Scenarios, as discussed further below, to ensure they are based on reasonable assumptions and better reflect future transmission system conditions and uncertainties in those future circumstances. In sum, incorporating Long-Term Scenarios into Long-Term Regional Transmission Planning provides an appropriate approach to ensure just and reasonable rates by accounting for the increasing uncertainty in the accuracy of assumptions over longer (*i.e.*, over 10 years) transmission planning horizons and mitigating the risks of under-building or over-building Long-Term Regional Transmission Facilities.

304. Further, we disagree with commenters that suggest that the Commission should not establish specific Long-Term Scenario requirements and that imposing general principles is sufficient to ensure just and reasonable rates. We find that Long-Term Regional Transmission Planning that does not incorporate Long-Term Scenarios that meet the requirements of this final order would fail to ensure that transmission providers identify Long-Term Transmission Needs, as well as identify and evaluate Long-Term Regional Transmission Facilities to address those needs. For example, relying on a single forecast of future transmission system conditions may limit transmission providers' and stakeholders' confidence in identified Long-Term Transmission Needs, and accordingly the evaluation of Long-Term Regional Transmission Facilities to address those needs. Further, failure to incorporate Long-Term Scenarios would increase the likelihood of piecemeal and relatively inefficient or less cost-effective transmission development. Accordingly, we find that requiring transmission providers to develop and use Long-Term Scenarios that meet the requirements established in this final order as part of Long-Term Regional Transmission Planning will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

305. Additionally, as stated above and in response to commenters that emphasize the importance of

⁶⁹² *Id.*

⁶⁹³ See, e.g., AEE Initial Comments at 7–8 (noting that reforms are needed to meet transmission needs driven by “market forces, state policies, and new reliability and resilience imperatives”); ELCON Initial Comments at 4 (“[L]ong term scenario planning should not be limited to anticipated resource mix but also take into consideration impacts on reliability and congestion management.”); New Jersey Commission Initial Comments at 2 (“[T]he Board stresses that most of the reforms the Commission is proposing would be necessary even in the absence of ‘changes in the resource mix and demand.’”) (citing NOPR, 179 FERC ¶ 61,028 at P 24); Renewable Northwest Initial Comments at 8 (noting how current transmission planning processes ignore both “trends in future generation and the impact of extreme weather events”) (citing NOPR, 179 FERC ¶ 61,028 at P 51); Southeast PIOs Initial Comments at 7–8 (noting that both intensifying “changes in the generation mix” and “increasingly common extreme weather and high-intensity, low frequency events” burden the existing transmission system).

⁶⁹⁴ In the NOPR, the Commission proposed to define Long-Term Scenarios as a tool to identify transmission needs driven by changes in the resource mix and demand—and enable the evaluation of transmission facilities to meet such transmission needs—across multiple scenarios that incorporate different assumptions about the future electric power system over a sufficiently long-term, forward-looking transmission planning horizon. NOPR, 179 FERC ¶ 61,028 at P 84.

⁶⁹⁵ Concerned Scientists Reply Comments at 18–19; NARUC Initial Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 86, 88).

⁶⁹⁶ See Policy Integrity Reply Comments at 2.

⁶⁹⁷ NARUC Initial Comments at 4.

collaboration in developing Long-Term Scenarios, this final order retains the requirements for an open, coordinated, and transparent local transmission planning process established in Order No. 890 and further required for regional transmission planning in Order No. 1000.⁶⁹⁸ For example, consistent with the transparency transmission planning principle,⁶⁹⁹ transmission providers must make transparent the methodology, criteria, assumptions, and data used to develop each Long-Term Scenario. Moreover, as described below, this final order requires that transmission providers provide meaningful opportunity for stakeholder input, including from state and local regulators, as well as non-jurisdictional entities, into the factors used to develop Long-Term Scenarios.

306. In response to PJM's request that the Commission clarify that the role of the state regulator is primary in developing Long-Term Scenarios, we note that, as described in the Stakeholder Process and Transparency determination within the Categories of Factors section, transmission providers retain the ultimate responsibility for transmission planning.⁷⁰⁰ As such, transmission providers have discretion, subject to the limits imposed in this final order, to weigh more heavily one source of information over another, such as weighing information related to a factor provided by a state regulator more heavily than information provided by other stakeholders. In response to California Energy Commission, we find that the final order does not preclude transmission providers from relying on scenarios developed by state agencies, provided that the Commission finds that the OATT provisions governing those Long-Term Scenarios' development comply with the Long-Term Scenarios requirements of this final order (e.g., transmission planning horizon and stakeholder input requirements). We decline to require the use of Long-Term Scenarios in all transmission planning processes, as requested by California Commission and City of New York. The record in this proceeding does not

demonstrate that the incorporation of Long-Term Scenarios in existing Order No. 1000 regional transmission planning processes is necessary to ensure that Long-Term Regional Transmission Planning is just and reasonable. In response to NYISO's request that transmission providers be allowed to use scenario planning in their existing Order No. 1000 regional transmission planning processes, while we agree that such a practice may offer benefits, we find that any such request amending existing transmission planning processes must be submitted in an FPA section 205 filing separate from their compliance filings to this final order.⁷⁰¹

C. Long-Term Scenarios Requirements

1. Transmission Planning Horizon

a. NOPR Proposal

307. In the NOPR, the Commission proposed to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon.⁷⁰²

308. The Commission preliminarily found that a 20-year transmission planning horizon requirement strikes a reasonable balance between the current transmission planning horizons used in many transmission planning regions and the 30-year or longer transmission planning horizon proposed by some ANOPR commenters. The Commission noted that the 30-year or longer transmission planning horizon was criticized by other commenters as speculative or too uncertain. The Commission also stated that a 20-year transmission planning horizon requirement may be reasonable because some transmission providers use a 20-year transmission planning horizon in existing regional transmission planning processes. In addition, the Commission stated that a 20-year transmission planning horizon would allow for sufficient time to identify, plan, and obtain siting and permitting approval for and to construct regional transmission facilities to meet long-term regional transmission needs, including those that may take longer than the average amount of time to go from the planning stage to in-service. Finally, the Commission stated that a 20-year transmission planning horizon would allow transmission providers to better

leverage economies of scale by sizing transmission facilities to meet not only nearer-term transmission needs, but also longer-term transmission needs driven by changes in the resource mix and demand over time. The Commission preliminarily found that by assessing transmission needs over a longer time horizon—for example, starting in year six⁷⁰³ through year 20 of the transmission planning horizon—Long-Term Regional Transmission Planning should be able to identify more efficient or cost-effective regional transmission facilities to address these needs.⁷⁰⁴

b. Comments

i. Support for 20-Year Transmission Planning Horizon

309. Many commenters support the Commission's proposal to require transmission providers to develop Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon.⁷⁰⁵ Several

⁷⁰³ The Commission noted that the North American Electric Reliability Corporation defines the long-term transmission planning horizon as covering year six through year 10 and beyond. *Id.* P 94 n.160.

⁷⁰⁴ *Id.* PP 97–99 (footnotes omitted).

⁷⁰⁵ ACORE Initial Comments at 1; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8; AEP Initial Comments at 5, 8–12; Amazon Initial Comments at 2–3; BP Initial Comments at 4–5; Breakthrough Energy Initial Comments at 12–13; Breakthrough Energy Supplemental Comments at 1; California Water Initial Comments at 14–15; Certain TDUs Initial Comments at 3, 19; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 12; Clean Energy States Initial Comments at 2; Concerned Scientists Reply Comments at 18–19; Cypress Creek Reply Comments at 4; DC and MD Offices of People's Counsel Initial Comments at 8; Environmental Groups Supplemental Comments at 2; Eversource Initial Comments at 14; Form Energy Initial Comments at 2; Georgia Commission Initial Comments at 2–3; GridLab Initial Comments at 5; Idaho Power Initial Comments at 4; Illinois Commission Initial Comments at 6; Indicated US Senators and Representatives Initial Comments at 1; Interwest Initial Comments at 4–5; ITC Initial Comments at 9–11; LADWP Initial Comments at 2; Minnesota State Entities Initial Comments at 4; National and State Conservation Organizations Initial Comments at 1; National Grid Initial Comments at 12–13; Nevada Commission Initial Comments at 7; New England for Offshore Wind Initial Comments at 2; New Jersey Commission Initial Comments at 9–10; NextEra Initial Comments at 62; NYISO Initial Comments at 2; Pacific Northwest State Agencies Initial Comments at 2; PG&E Initial Comments at 2; Policy Integrity Initial Comments at 10; PIOs Initial Comments at 15; R Street Initial Comments at 6; SEIA Initial Comments at 6; SoCal Edison Initial Comments at 11–12; Southeast PIOs Initial Comments at 43; SPP Initial Comments at 5–6; SPP Market Monitor Initial Comments at 4–5; State Officials Supplemental Comments at 1 (citing US Climate Alliance Initial Comments at 2); US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 10; Vermont Electric and Vermont Transco Initial

⁶⁹⁸ Order No. 1000, 136 FERC ¶ 61,051 at PP 150–152; Order No. 890, 118 FERC ¶ 61,119 at P 435.

⁶⁹⁹ Order No. 890, 118 FERC ¶ 61,119 at P 471.

⁷⁰⁰ *Id.* P 454. There, we stated in response to the suggestion by some commenters that we require transmission providers to allow customers to collaboratively develop transmission plans with transmission providers on a co-equal basis that transmission planning is the tariff obligation of each transmission provider, and the *pro forma* OATT planning process adopted in the final rule is the means to see that it is carried out in a coordinated, open, and transparent manner, in order to ensure that customers are treated comparably. Therefore, the ultimate responsibility for planning remains with transmission providers.

⁷⁰¹ We note that an exception to the requirement to file a separate FPA section 205 filing applies if transmission providers were to propose a unified transmission planning process, as discussed above. See *supra* Participation in Long-Term Regional Transmission Planning section.

⁷⁰² NOPR, 179 FERC ¶ 61,028 at PP 97–100.

commenters generally consider a 20-year transmission planning horizon to be reasonable, acceptable, or appropriate.⁷⁰⁶ Some commenters argue that a 20-year transmission planning horizon provides a reasonable balance between shorter- and longer-term transmission planning horizons.⁷⁰⁷ National Grid states that a 20-year transmission planning horizon balances the benefits of prospective transmission planning with the greater uncertainty that comes with forecasting system needs over a longer period.⁷⁰⁸ Numerous commenters argue that a 20-year transmission planning horizon will help to improve the efficiency and cost of developing transmission and to assess future transmission needs.⁷⁰⁹

310. New Jersey Commission argues that a 20-year transmission planning horizon should help to make long-term multi-driver transmission projects viable by identifying needs and opportunities in a timeframe that allows states to have a meaningful conversation about voluntarily funding such projects.⁷¹⁰ Policy Integrity argues that it is crucial to model what is going to be needed over the next 20 years to ensure that short- and medium-term transmission projects are built efficiently, stating that a longer transmission planning horizon is reasonable in the context of long-lived transmission assets with long lead times.⁷¹¹

311. US DOE asserts that there is sufficient evidence to extend the transmission planning horizon to a minimum of 20 years for Long-Term Regional Transmission Planning to capture power sector changes that occur during transmission development.⁷¹² PIOs note that panelists at the November 2021 Technical Conference suggested a 20-year transmission planning horizon is necessary, in part, due to long-term public policy goals.⁷¹³

Comments at 2; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

⁷⁰⁶ CAISO Initial Comments at 21; EEL Initial Comments at 11; Entergy Initial Comments at 9; NARUC Initial Comments at 5; New York TOs Initial Comments at 10; Pine Gate Initial Comments at 19–20; PPL Initial Comments at 6; WIRES Initial Comments at 7.

⁷⁰⁷ DC and MD Offices of People's Counsel Initial Comments at 8–9; LADWP Initial Comments at 2–3; National Grid Initial Comments at 12–13.

⁷⁰⁸ National Grid Initial Comments at 12–13.

⁷⁰⁹ AEP Reply Comments at 4–5 (citing MTEP2017 Review at 33–34); Amazon Initial Comments at 2–3; BP Initial Comments at 5; Certain TDUs Reply Comments at 5; PIOs Initial Comments at 15.

⁷¹⁰ New Jersey Commission Initial Comments at 9–10, 28.

⁷¹¹ Policy Integrity Initial Comments at 10.

⁷¹² US DOE Initial Comments at 10.

⁷¹³ PIOs Initial Comments at 15 (citing Tr. 129–137 (multiple witnesses)).

Acadia Center and CLF similarly argue that transmission planners should plan over long-term horizons to factor in predictable trends, such as timelines required under state laws and policies.⁷¹⁴

312. Several commenters emphasize that a transmission planning horizon of 20 years is sufficient to account for the amount of time needed to develop transmission projects, considering the complexity and challenges of major transmission development.⁷¹⁵ Eversource states that a long-term perspective is necessary to take advantage of the economies of scale that large transmission projects can enable, as well as to incorporate anticipated changes in generation and load beyond the traditional transmission planning horizon.⁷¹⁶ Illinois Commission states that a 20-year transmission planning horizon is necessary to properly plan and build transmission and generation resources.⁷¹⁷ LADWP states that a 20-year transmission planning horizon provides enough time for transmission projects to be developed and placed in service when such projects require new rights-of-way without becoming too speculative.⁷¹⁸ NextEra contends that a 20-year transmission planning horizon will ensure that transmission planners anticipate and plan transmission facilities for needs driven by changes in the resource mix and demand.⁷¹⁹

313. PIOs state that a 20-year transmission planning horizon should be the minimum timeframe, explaining that because transmission facilities can take 15 years to plan, permit, and construct, a 20-year transmission planning horizon can result in just-in-time planning, where the transmission plan is developed shortly before the process for siting and permitting must begin.⁷²⁰ GridLab asserts that a 20-year transmission planning horizon might identify regional transmission needs that occur after year 10, as well as transmission projects that would be selected and approved in later transmission planning cycles.⁷²¹

314. Clean Energy States support quick adoption of at least a 20-year planning horizon because many of their member states have established 100%

⁷¹⁴ Acadia Center and CLF Initial Comments at 4.

⁷¹⁵ Eversource Initial Comments at 14; Illinois Commission Initial Comments at 6; LADWP Initial Comments at 2; NextEra Initial Comments at 62–63; PG&E Initial Comments at 2; PIOs Initial Comments at 15.

⁷¹⁶ Eversource Initial Comments at 14.

⁷¹⁷ Illinois Commission Initial Comments at 6.

⁷¹⁸ LADWP Initial Comments at 2.

⁷¹⁹ NextEra Initial Comments at 62–63.

⁷²⁰ PIOs Initial Comments at 15.

⁷²¹ GridLab Initial Comments at 8–9.

clean energy power sector or zero-carbon goals for their state economies by 2040 or 2050.⁷²² California Municipal Utilities, on the other hand, support a 20-year transmission planning horizon, but caution that transmission costs identified can be significant and could rely upon speculative resources that may not come to fruition, namely offshore wind development.⁷²³

315. Many commenters highlight transmission planning regions with existing long-term transmission planning that either does or will conform to the 20-year transmission planning horizon proposed in the NOPR.⁷²⁴ MISO commits to continue using its 20-year forecast period under this proposed reform.⁷²⁵ SPP states that it currently performs a 20-year assessment that incorporates Long-Term Scenarios at least once every five years.⁷²⁶ New York Transco notes that NYISO's transmission planning process utilizes multiple cases and scenarios over a 20-year evaluation horizon.⁷²⁷ Acadia Center and CLF note that ISO–NE recently gained Commission approval for longer-term transmission studies to undertake long-term transmission planning to 2050.⁷²⁸

316. CAISO states that it currently approves transmission projects in its annual transmission planning process based on a 10-year outlook, although the CAISO OATT allows for a longer 20-year transmission horizon outlook to reliably and cost-effectively account for California's greenhouse gas and renewable energy objectives.⁷²⁹ CAISO explains that its 20-year outlook does not include a process for approving specific transmission projects, but rather allows considerations beyond 10 years to inform decisions in its annual

⁷²² Clean Energy States Initial Comments at 2.

⁷²³ California Municipal Utilities Initial Comments at 6–7.

⁷²⁴ Acadia and CLF Initial Comments at 3; CAISO Initial Comments at 15; California Municipal Utilities Initial Comments at 5–6; Clean Energy States Initial Comments at 2; ISO/RTO Council Initial Comments at 3–4; MISO Initial Comments at 33; MISO TOs Initial Comments at 17; New York TOs Initial Comments at 2; New York Transco Initial Comments at 5; NextEra Initial Comments at 63–64 (discussing efforts at CAISO, SPP, and MISO); Omaha Public Power Initial Comments at 4; PIOs Initial Comments at 14 (pointing to NYISO and MISO as examples of transmission planning regions already successfully using a 20-year transmission planning horizon); SPP Initial Comments at 5–6.

⁷²⁵ MISO Initial Comments at 33.

⁷²⁶ SPP Initial Comments at 5–6.

⁷²⁷ New York Transco Initial Comments at 5 (citing NYISO, NYISO Tariffs, NYISO OATT, attach. Y section 31.4a (Public Policy Requirements Planning Process) (23.0.0), section 31.4.6.1).

⁷²⁸ Acadia Center and CLF Initial Comments at 3.

⁷²⁹ CAISO Initial Comments at 15.

transmission planning process.⁷³⁰ California Municipal Utilities also highlight CAISO's existing transmission planning processes, noting that its 20-year transmission outlook calls for an estimated combined capital cost of \$30.5 billion.⁷³¹ NextEra notes that, while many transmission planning regions use or will use a 20-year transmission planning horizon, no requirements exist to ensure that these practices persist.⁷³²

317. Several commenters reference existing long-term planning processes as support for the Commission's proposed 20-year transmission planning horizon.⁷³³ NextEra and ACEG explain that longer time horizons are embedded into existing integrated resource plans, through law or common practice, and extend into and beyond 2040 to meet ambitious resource goals.⁷³⁴ R Street argues that, for benchmarking purposes, 20- to 25-year planning horizons have been a best practice for integrated resource planning for decades.⁷³⁵

318. LADWP asserts that the proposed 20-year transmission planning horizon is likely the least disruptive horizon because of its current use by many transmission providers. LADWP further argues that a consistent transmission planning horizon will optimize asset investment and minimize public impacts; facilitate planning, coordination, and development of large-scale regional transmission projects; and ensure that transmission providers consider the same end point assessments of the evolving resource mix, environmental requirements that develop beyond a typical 10-year

period, and significant maintenance and retirement issues.⁷³⁶

ii. Requests for Flexibility

319. Several commenters recommend that the Commission provide transmission providers in each transmission planning region with the flexibility to propose other transmission planning horizons that may be appropriate and beneficial based on their planning processes.⁷³⁷ APS states that it is not convinced that a prescriptive approach will yield the benefits that the Commission seeks.⁷³⁸

320. NESCOE states that there is not one "right" transmission planning horizon and that it does not support a one-size-fits-all transmission planning horizon requirement.⁷³⁹ NESCOE requests that the Commission allow transmission providers in each transmission planning region to demonstrate that existing tariff provisions are consistent with or superior to a final order mandating a minimum transmission planning horizon, explaining—along with ISO-NE—that ISO-NE's Tariff does not provide a prescribed timeframe to request transmission analyses based on state-provided scenarios.⁷⁴⁰ Relatedly, California Commission suggests that, instead of mandating a 20-year transmission planning horizon, the Commission should adopt NYISO's recommendation to provide transmission providers with the discretion, up to 20 years, to plan for their needs.⁷⁴¹

321. PG&E understands that not every transmission need identified in the latter years of a 20-year transmission planning horizon will require immediate selection resolution, and it therefore asks the Commission to give individual transmission planning regions the flexibility to determine how to allow for monitoring and updating planning assumptions for transmission projects that meet transmission needs

beyond 10 years.⁷⁴² ISO-NE argues that the Commission should permit an approach that allows (but does not require) a transmission planning horizon beyond 10 years because the 20-year transmission planning horizon could potentially limit the identification of system issues during interim years, inhibit adaptation to evolving policies, and preclude the transmission planning process from considering public policies that may include shorter timeframes, which may limit the ability to adapt to emerging needs or changing laws.⁷⁴³ NESCOE contends that a rigid 20-year transmission planning horizon may be counterproductive and could divert resources focused on meeting requests under ISO-NE's longer-term transmission planning process to study a time horizon that states, stakeholders, and ISO-NE may not find useful.⁷⁴⁴

322. OMS argues that the final order should permit flexibility in transmission planning horizons and enable transmission planning regions to meet objectives through routine scenario-based planning within an appropriate study window.⁷⁴⁵ Industrial Customers assert that transmission planning horizons should consider the time to identify, plan, and obtain siting and permitting approval to construct regional transmission facilities, and that timing can vary dramatically by region. Industrial Customers believe a stringent 20-year transmission planning horizon could create more uncertainty, resulting in stranded transmission investments and increased transmission rates because it is difficult, if not impossible, to forecast transmission needs and requirements 20 years into the future.⁷⁴⁶

323. PJM States recommend, and Clean Energy Associations agree, that instead of requiring a transmission planning horizon of a particular length, the Commission should require each transmission provider to demonstrate that the transmission planning horizon it chooses is adequate to achieve the goals of Long-Term Regional Transmission Planning.⁷⁴⁷

324. New York State Department recommends that the final order allow states to determine the appropriate transmission planning horizon since New York Public Service Commission has already issued orders directing long-term transmission and distribution

⁷³⁰ *Id.* at 15–16.

⁷³¹ California Municipal Utilities Initial Comments at 5–6 (citing CAISO, *20-Year Transmission Outlook*, Table ES–1: Cost estimate of transmission development to integrate resources of SB100 Starting Point scenario (Jan. 31, 2022), <http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf>).

⁷³² NextEra Initial Comments at 64–65.

⁷³³ BP Initial Comments at 5 (citing CAISO's transmission planning process); Idaho Power Initial Comments at 4 (noting NorthernGrid's 20-year transmission planning horizon); Interwest Initial Comments at 5 (noting existing state resource planning processes); Nevada Commission Initial Comments at 7 (noting its integrated resource planning process requiring a minimum of eight years); PIOs Initial Comments at 14 (noting 20-year horizons used by NYISO, MISO, and other transmission planning regions); SPP Market Monitor Initial Comments at 4–5 (noting SPP's existing transmission planning process); Western PIOs Initial Comments at 28–29 (noting Western Electricity Coordinating Council's planning scenarios and the integrated resource planning timelines of western vertically-integrated utilities).

⁷³⁴ ACEG Reply Comments at 4–5; NextEra Initial Comments at 62–63.

⁷³⁵ R Street Initial Comments at 6.

⁷³⁶ LADWP Initial Comments at 2.

⁷³⁷ Ameren Initial Comments at 13; APPA Initial Comments at 5; California Water Initial Comments at 14–15; EEL Initial Comments at 11; Indicated PJM TOs Initial Comments at 10; ISO-NE Initial Comments at 22–23; MISO TOs Initial Comments at 17; NARUC Initial Comments at 5–6; NESCOE Initial Comments at 25; New York State Department Initial Comments at 3; New York TOs Initial Comments at 10; Pennsylvania Commission Initial Comments at 5; TANC Initial Comments at 10; WIRES Initial Comments at 7; Xcel Initial Comments at 9.

⁷³⁸ APS Initial Comments at 3.

⁷³⁹ NESCOE Initial Comments at 23–24.

⁷⁴⁰ ISO-NE Initial Comments at 22–23; NESCOE Initial Comments at 24–25.

⁷⁴¹ California Commission Initial Comments at 11–12 (citing NYISO ANOPR Initial Comments at 37).

⁷⁴² PG&E Initial Comments at 4–6.

⁷⁴³ ISO-NE Initial Comments at 22–23.

⁷⁴⁴ NESCOE Initial Comments at 24–25.

⁷⁴⁵ OMS Initial Comments at 4–5.

⁷⁴⁶ Industrial Customers Reply Comments at 4–5.

⁷⁴⁷ Clean Energy Associations Reply Comments at 5–6; PJM States Initial Comments at 4.

planning with undefined terms.⁷⁴⁸ EEI and US Chamber of Commerce explain that state regulators may not appreciate a rigid 20-year transmission planning horizon requirement given that some state resource procurement processes use a 10-year outlook, and the proposed transmission planning process may thus make resource decisions that are not state-sanctioned.⁷⁴⁹ Consistent with their Coordinated Grid Planning Process, New York Commission and NYSEDA assert that the Commission should allow state regulators to help determine the appropriate transmission planning horizon, especially in a single-state RTO/ISO such as NYISO.⁷⁵⁰

325. Louisiana Commission states that a 20-year transmission planning horizon may be longer than the planning horizon utilized in state integrated resource planning, explaining that its integrated resource planning rules allow for a 20-year default planning period, but also for alternative periods, and more importantly, require 5-year action plans.⁷⁵¹

326. APPA argues, and TANC concurs, that the Commission should allow transmission planning regions to incorporate cost and benefit-tracking mechanisms to reduce the risk of speculative transmission projects.⁷⁵²

iii. Requests for a Different Transmission Planning Horizon

327. Several commenters argue that a 20-year transmission planning horizon is too long.⁷⁵³ Indicated PJM TOs contend that the Commission should ensure that transmission planning horizons result in the identification of transmission facilities that can be realistically planned and developed, and that 20 years may be too long given rapidly changing technology, generation mix, and demand patterns.⁷⁵⁴ Mississippi Commission also favors a

shorter transmission planning horizon, arguing that there is too much uncertainty to plan 20 to 40 years into the future.⁷⁵⁵ NRECA argues that a 20-year transmission planning horizon may allow more alternatives to be considered, but cost efficacy is not guaranteed. Further, NRECA argues that planning beyond 10 years will by necessity devolve into a top-down process that would, at best, relegate actual load-serving entity resource plans and demand forecasts to a secondary status or, at worst, ignore them altogether, violating FPA section 217(b)(4).⁷⁵⁶

328. PJM Market Monitor states that uncertainty increases significantly as the transmission planning horizon is extended, and the transmission planning process should be both long-term and flexible, allowing transmission planners to change plans as reality changes.⁷⁵⁷ Similarly, US Chamber of Commerce asserts that, as the length of the transmission planning horizon increases, the number of assumptions increases and the quality of assumptions decreases, rendering costs and benefits less certain. US Chamber of Commerce states that today's transmission grid was not forecasted at the turn of the century, and, thus, forecasts made today for a similar period are likely to under or over-shoot transmission needs due to new and advancing generation technologies with commercial operation timeframes not yet known.⁷⁵⁸ Nebraska Commission states that a 20-year transmission planning horizon may reduce the transmission planning process to an academic exercise due to the amount of speculation necessarily involved.⁷⁵⁹

329. Industrial Customers state that the Commission has not ruled against transmission planning horizons under 15 years and has acknowledged that the average time needed to develop and build a transmission project is 10 years.⁷⁶⁰ Industrial Customers assert that, contrary to the Commission's view, most transmission planners use 10-year transmission planning horizons, and transmission investment should be driven by shorter timeframes to plan for economic and reliability needs.⁷⁶¹ Ohio

Consumers note that the 5-year timeframe used by PJM's DFAX method is characterized by high uncertainty, so a longer timeframe would exacerbate inaccuracies.⁷⁶²

330. Several commenters argue that a 10-year transmission planning horizon could reduce speculation, such as with respect to the changing resource mix.⁷⁶³ NRG states that a shorter, 10-year transmission planning horizon would fit within the time horizon necessary to make transmission investment decisions and still reflect regional policy goals.⁷⁶⁴ Utah Commission notes that NorthernGrid's members in 2020 adopted a 10-year transmission planning horizon and objects to being compelled to abandon that planning horizon in favor of a one-size-fits-all mandate.⁷⁶⁵

331. PJM and Exelon advocate for a 15-year transmission planning horizon to reduce uncertainty and enhance reliability.⁷⁶⁶ Exelon argues that a 15-year transmission planning horizon may yield less uncertain forecasts that are more likely to be actionable and better align with target dates in public policies.⁷⁶⁷ PJM argues that its current 15-year transmission planning horizon is sufficient to plan and develop needed transmission, and that forecasts of fuel prices, load trends, generation retirement, and other relevant parameters become more uncertain the further one looks out. Moreover, PJM asserts, a longer transmission planning horizon leads to a greater probability that a transmission provider will commit to a transmission project that will look unfortunate in hindsight.⁷⁶⁸

332. Some commenters argue that a transmission planning horizon longer than 20 years may be warranted to capture the longer-term benefits of transmission facilities.⁷⁶⁹ ACEG recommends that the Commission

⁷⁴⁸ New York State Department Initial Comments at 3.

⁷⁴⁹ EEI Initial Comments at 11; US Chamber of Commerce Initial Comments at 6.

⁷⁵⁰ New York Commission and NYSEDA Initial Comments at 10–12.

⁷⁵¹ Louisiana Commission Reply Comments at 8 (citing Corrected General Order Docket No R–30021 (LPSC 3/12/2012)).

⁷⁵² APPA Initial Comments at 26, 36; TANC Initial Comments at 10.

⁷⁵³ Exelon Initial Comments at 4, 7–8; Indicated PJM TOs Initial Comments at 10; Industrial Customers Initial Comments at 18; Louisiana Commission Reply Comments at 13; Mississippi Commission Initial Comments at 12; Nebraska Commission Initial Comments at 3–4; NRECA Initial Comments at 27–28; NRG Initial Comments at 6–9, 14; Ohio Consumers Initial Comments at 20; Omaha Public Power Initial Comments at 3–4; PJM Initial Comments at 5, 58–62; US Chamber of Commerce Initial Comments at 5–6; Utah Commission Initial Comments at 13.

⁷⁵⁴ Indicated PJM TOs Initial Comments at 10.

⁷⁵⁵ Mississippi Commission Initial Comments at 12; *see also* Louisiana Commission Reply Comments at 13 (citing Mississippi Commission Initial Comments at 12).

⁷⁵⁶ NRECA Initial Comments at 27–28.

⁷⁵⁷ PJM Market Monitor Initial Comments at 3.

⁷⁵⁸ US Chamber of Commerce Initial Comments at 6.

⁷⁵⁹ Nebraska Commission Initial Comments at 3.

⁷⁶⁰ Industrial Customers Initial Comments at 18.

⁷⁶¹ Industrial Customers Initial Comments at 16–19 (referencing NYISO and the Eastern

Interconnection Planning Collaborative planning processes).

⁷⁶² Ohio Consumers Initial Comments at 20.

⁷⁶³ Nebraska Commission Initial Comments at 3–4; NRG Initial Comments at 6–9, 14; Omaha Public Power Initial Comments at 3–4.

⁷⁶⁴ NRG Initial Comments at 6–9, 14.

⁷⁶⁵ Utah Commission Initial Comments at 13.

⁷⁶⁶ Exelon Initial Comments at 4, 7–8; PJM Initial Comments at 5, 58–62.

⁷⁶⁷ Exelon Initial Comments at 4, 7–8.

⁷⁶⁸ PJM Initial Comments at 59–62 (citing *Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-fired Resources*, Notice of Technical Conference, Docket No. AD05–3–000, at 1 (issued Feb. 16, 2005)).

⁷⁶⁹ ACEG Initial Comments at 6–7, 24; CARE Coalition Initial Comments at 40–41; Interwest Initial Comments at 5; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 19–20; PIOs Initial Comments at 15; SEIA Initial Comments at 6.

consider up to a 40-year transmission planning horizon to match the expected life of most transmission assets.⁷⁷⁰ CARE Coalition argues that a 40-year transmission planning horizon would be consistent with standard practice in economics and public policy of evaluating benefits over the life of the asset, and that the long lead time to develop transmission facilities justifies a longer planning horizon.⁷⁷¹

iv. Opposition to Requests for a Different Transmission Planning Horizon

333. Several commenters dispute claims that a 20-year transmission planning horizon introduces risks from uncertainty and that a shorter planning horizon is more appropriate.⁷⁷² Southeast PIOs claim that the risk of unaddressed transmission needs grows over time because of long lead times needed for transmission development, and that SERTP's 10-year transmission planning horizon prevented Georgia Power from using that process to plan for its long-term North Georgia Reliability & Resilience Plan and its goal to integrate 6,000 MW of renewable resources by 2035.⁷⁷³ Southeast PIOs assert that a longer transmission planning horizon will put future transmission needs on the radar for transmission planners and, if updated frequently, allow transmission providers to select transmission facilities conditional on subsequent transmission planning cycles, which affords planners flexibility to determine the need for the facility and whether there are more cost-effective alternatives.⁷⁷⁴ ACORE notes that the NOPR addresses the uncertainty about the future by requiring the use of multiple Long-Term Scenarios that are revised every three years.⁷⁷⁵

334. Several commenters state that the transmission planning horizon should not extend beyond 20 years to avoid overly speculative long-term forecasts.⁷⁷⁶ Entergy asserts that looking

beyond 20 years would increase the likelihood of errors, risk billions of dollars in investments that may prove to be misguided, and amplify the risk of planning a transmission system that poorly aligns with actual future needs.⁷⁷⁷ Illinois Commission states that a transmission planning horizon longer than 20 years would make it difficult to accurately predict the factors relevant to transmission planning.⁷⁷⁸ Clean Energy Buyers propose that transmission providers seeking to adopt a transmission planning horizon beyond 20 years should be required to demonstrate the justness and reasonableness of that transmission planning horizon.⁷⁷⁹

335. Certain TDUs and Louisiana Commission oppose a 40-year transmission planning horizon.⁷⁸⁰ Certain TDUs emphasize that, as evidenced by the Michigan Thumb Loop transmission project, assumptions such as the resource mix can change in as few as seven years.⁷⁸¹ Louisiana Commission argues that longer periods, such as the 40-year transmission planning horizon proposed by some commenters, will greatly increase the risk for errors and wasted investments. According to Louisiana Commission, transmission planning horizons should neither exceed the availability of reasonable data and assumptions nor create unnecessary risks that ratepayers will be required to fund transmission facilities that do not deliver expected benefits.⁷⁸²

v. Meaning and Scope of Transmission Planning Horizon

336. Several commenters request that the Commission define the 20-year transmission planning horizon as a simple 20-year period, and not a 20-year period starting from the estimated in-service date of the transmission facilities, which would result in forecasting transmission needs beyond 20 years.⁷⁸³ Kentucky Commission Chair Chandler states that the usefulness of Long-Term Regional Transmission Planning and measuring

Commission Initial Comments at 5; US Chamber of Commerce Initial Comments at 4, 6.

⁷⁷⁷ Entergy Initial Comments at 9–11.

⁷⁷⁸ Illinois Commission Initial Comments at 6.

⁷⁷⁹ Clean Energy Buyers Initial Comments at 12–13.

⁷⁸⁰ Certain TDUs Reply Comments at 3–6 (citing ACEG Initial Comments at 24); Louisiana Commission Reply Comments at 8.

⁷⁸¹ Certain TDUs Reply Comments at 3–6.

⁷⁸² Louisiana Commission Reply Comments at 8.

⁷⁸³ Kentucky Commission Chair Chandler Reply Comments at 2; National Grid Initial Comments at 12–13; PJM States Initial Comments at 3; PPL Initial Comments at 6; US Chamber of Commerce Initial Comments at 6.

benefits 20 years after a transmission project's in-service date will decrease if each project's relative benefits cannot be adequately measured and identified.⁷⁸⁴ PPL argues that tying the transmission planning horizon to the study date rather than the solution in-service date will facilitate a more realistic, certain, and simple transmission planning process and reduce the need for additional analysis.⁷⁸⁵ US Chamber of Commerce adds that beginning at the in-service date of the transmission facilities would extend the effective transmission planning horizon to 25–30 years, thereby further increasing the uncertainty of Long-Term Regional Transmission Planning; thus, US Chamber of Commerce argues the Commission should use the 20-year transmission planning horizon as a ceiling, rather than a floor, consistent with the far end of most state planning horizons, which would protect transmission planners from being forced to plan beyond the requirements of applicable state law.⁷⁸⁶

337. Policy Integrity requests that the Commission clarify the details of the 20-year time horizon, stating that it is unclear whether the Commission intended the 20-year time horizon for Long-Term Regional Transmission Planning to be tied to construction commencing in year 20.⁷⁸⁷ ISO-NE and Policy Integrity seek clarification that, if the Commission requires that transmission providers must study what is needed over the next 20 years, transmission providers are not precluded from evaluating what needs to be built in the short and medium terms.⁷⁸⁸ Industrial Customers assert that the proposed 20-year transmission planning horizon is unclear because some commenters interpret the Commission's proposal as requiring a 20-year transmission planning horizon for Long-Term Regional Transmission Planning,⁷⁸⁹ while others argue it requires a 20-year transmission planning horizon in existing regional transmission planning processes.⁷⁹⁰

338. Several commenters support a 20-year transmission planning horizon if Long-Term Scenarios are used to inform the development of transmission

⁷⁸⁴ Kentucky Commission Chair Chandler Reply Comments at 2.

⁷⁸⁵ PPL Initial Comments at 6.

⁷⁸⁶ US Chamber of Commerce Initial Comments at 6.

⁷⁸⁷ Policy Integrity Initial Comments at 5.

⁷⁸⁸ ISO-NE Initial Comments at 23; Policy Integrity Initial Comments at 5.

⁷⁸⁹ Industrial Customers Reply Comments at 5–6 (citing NARUC Initial Comments at 5).

⁷⁹⁰ Industrial Customers Reply Comments at 5–6 (citing California Commission Initial Comments at 11).

⁷⁷⁰ ACEG Initial Comments at 6, 24.

⁷⁷¹ CARE Coalition Initial Comments at 40–41.

⁷⁷² ACORE Reply Comments at 5 (citing EPSA Initial Comments at 7; ITC Initial Comments at 9; Mississippi Commission Initial Comments at 12; PJM Initial Comments at 58–62); Concerned Scientists Reply Comments at 18–19; PJM Initial Comments at 58–62; Southeast PIOs Reply Comments at 23–25 (citing Dominion Initial Comments at 19; Southern Initial Comments at 19, 32–33).

⁷⁷³ Southeast PIOs Reply Comments at 24 (citing Southeast PIOs Initial Comments at 27–28).

⁷⁷⁴ *Id.* at 23–25.

⁷⁷⁵ ACORE Reply Comments at 5.

⁷⁷⁶ Arizona Commission Initial Comments at 3–4; California Commission Initial Comments at 11–13; Entergy Initial Comments at 9–11; Georgia Commission Initial Comments at 2–3; Pennsylvania

facilities but not used to select transmission facilities or to dictate construction.⁷⁹¹ TANC does not believe that a 20-year transmission planning horizon should be used for local transmission planning processes or selection.⁷⁹² Nebraska Commission states that using a 20-year transmission planning horizon for only research, study, and projections will avoid speculation, increased costs, and unjust and unreasonable rates.⁷⁹³ NRECA asserts that using a 20-year transmission planning horizon in Long-Term Regional Transmission Planning to select transmission projects will not produce the granularity and certainty needed to assign costs to beneficiaries.⁷⁹⁴ Similarly, Ohio Consumers argue that too little is known about the location of future loads and resources and the direction of power flows over 20 years to use a 20-year transmission planning horizon for cost allocation purposes.⁷⁹⁵ NRG argues that use of a 20-year transmission planning horizon to allocate costs will lead to unjust and unreasonable outcomes, and instead, a 10-year transmission planning horizon is appropriate.⁷⁹⁶ New England Systems state that the Commission should adjust the NOPR's focus on transmission planning horizons toward an evolutionary and evidence-based transmission planning process aimed at mitigating avoidable costs for operating generation out of economic merit order and at improving the utilization of renewable resources that experience curtailment due to congestion.⁷⁹⁷

339. Some commenters support a 20-year transmission planning horizon only if the latter portion of the planning horizon is not used to direct the development of transmission facilities.⁷⁹⁸ SERTP Sponsors state that the Commission should not require that regional transmission expansion be

based on transmission planning horizons that are incompatible with the planning horizons used for integrated resource planning or supply-side resource plan development, or that involve a degree of speculation that the states comprising a transmission planning region are not willing to accept.⁷⁹⁹ SPP Market Monitor contends that if the Commission requires all RTOs/ISOs to perform a 20-year study, the final order should also provide guidance on how information determined in that long-term study will be used. SPP Market Monitor supports a secondary, shorter-term transmission planning horizon of 10 years that could be based on the results of the longer-term 20-year studies.⁸⁰⁰

340. Shell suggests that the 20-year transmission planning horizon include a developmental "Actionable Period" for the first 10 years, during which developers may be willing to invest in generation projects, or the RTOs/ISOs or utilities may be willing to commit to and authorize the construction of new transmission. Shell proposes that there would be an "Indicative Period" for the following 10 years, which would be used to drive the Actionable Period so that the Commission establishes a process that converges and integrates short, medium, and long-term planning. Shell asserts that its proposal could foster more comprehensive and efficient Long-Term Regional Transmission Planning and inform existing regional transmission planning processes.⁸⁰¹ To remove speculative assumptions from Long-Term Regional Transmission Planning, Arizona Commission similarly suggests that the Commission divide the 20-year transmission planning horizon into two equal parts: a "more certain" forecast and a "flexible" forecast.⁸⁰² Likewise, APS recommends that the Commission adopt a 20-year transmission planning horizon for "potential projects" and a 10-year planning horizon for "planned projects" to provide greater regional flexibility.⁸⁰³

341. Kansas Commission, Mississippi Commission, and NRECA state that the results of Long-Term Regional Transmission Planning should be considered informational only.⁸⁰⁴ Kansas Commission requests that the Commission establish solid evidentiary and policy bases to support a 20-year transmission planning horizon before

imposing such a requirement.⁸⁰⁵ Mississippi Commission believes that transmission construction decisions should use a 10-year transmission planning horizon.⁸⁰⁶

342. Some commenters rebut arguments that Long-Term Regional Transmission Planning should be performed for informational purposes only.⁸⁰⁷ ACEG contends that adopting the proposed transmission planning methods is essential to accomplishing the Commission's responsibilities and that less stringent requirements have not led to much-needed development of high-capacity transmission throughout the country. ACEG further states that providing informational reports will do little to remedy undue discrimination and achieve actual transmission plans.⁸⁰⁸ DC and MD Offices of People's Counsel state that the potential benefits to ratepayers and other stakeholders of a 20-year transmission planning horizon is significantly diminished if transmission planning is simply an academic exercise, without actual impact on future transmission development.⁸⁰⁹ SEIA argues that the Commission should mandate that scenarios developed under the final order be used in transmission planning rather than for informational purposes only or contingent on the approval of state regulators.⁸¹⁰

343. Business Council for Sustainable Energy states that transmission planning should consider the length of time that it takes for transmission assets to be built and the estimated useful life of those facilities.⁸¹¹ California Municipal Utilities argue, and TANC concurs, that any lengthening of the transmission planning horizon must be accompanied by consumer protections that guard against speculative siting of generation and a rigorous re-evaluation of planning assumptions and other relevant factors, such as commercial viability of transmission projects and the associated resources.⁸¹²

c. Commission Determination

344. We adopt the NOPR proposal to require transmission providers in each transmission planning region to develop

⁷⁹¹ NARUC Initial Comments at 5; Nebraska Commission Initial Comments at 3; Northwest and Intermountain Initial Comments at 7, 13; NRECA Initial Comments at 23, 29; NRG Initial Comments at 6–9, 14; Ohio Consumers Initial Comments at 20; *see also* Dominion Reply Comments at 4–5 (citing NARUC Initial Comments at 5); PJM States Reply Comments at 9 (citing NARUC Initial Comments at 5).

⁷⁹² TANC Initial Comments at 10.

⁷⁹³ Nebraska Commission Initial Comments at 3.

⁷⁹⁴ NRECA Initial Comments at 23–24 (citing GDS Assocs., Inc., Report, at 10 (Aug. 17, 2022)).

⁷⁹⁵ Ohio Consumers Initial Comments at 1, 20.

⁷⁹⁶ NRG Initial Comments at 6–9, 14.

⁷⁹⁷ New England Systems Initial Comments at 21–22.

⁷⁹⁸ APS Initial Comments at 3–4; Kansas Commission Initial Comments at 13–14; Maryland Energy Administration Initial Comments at 3; SERTP Sponsors Initial Comments at 20; Shell Initial Comments at 21; SPP Market Monitor Initial Comments at 5–6.

⁷⁹⁹ SERTP Sponsors Initial Comments at 20.

⁸⁰⁰ SPP Market Monitor Initial Comments at 5–6.

⁸⁰¹ Shell Initial Comments at 19–23.

⁸⁰² Arizona Commission Initial Comments at 3–4.

⁸⁰³ APS Initial Comments at 3–4.

⁸⁰⁴ Kansas Commission Initial Comments at 13–14; Mississippi Commission Reply Comments at 6; NRECA Initial Comments at 23.

⁸⁰⁵ Kansas Commission Initial Comments at 13.

⁸⁰⁶ Mississippi Commission Reply Comments at 6.

⁸⁰⁷ ACEG Reply Comments at 10; DC and MD Offices of People's Counsel Reply Comments at 5; SEIA Reply Comments at 2.

⁸⁰⁸ ACEG Reply Comments at 10.

⁸⁰⁹ DC and MD Offices of People's Counsel Reply Comments at 5.

⁸¹⁰ SEIA Reply Comments at 2.

⁸¹¹ Business Council for Sustainable Energy Initial Comments at 4.

⁸¹² California Municipal Utilities Initial Comments at 3; TANC Initial Comments at 10.

Long-Term Scenarios as part of Long-Term Regional Transmission Planning using no less than a 20-year transmission planning horizon. We further clarify that using a transmission planning horizon of no less than 20 years means that transmission providers must develop Long-Term Scenarios to identify Long-Term Transmission Needs that will materialize in the 20 years or more following the commencement of the Long-Term Regional Transmission Planning cycle.

345. In requiring a transmission planning horizon of not less than 20 years, we strike a balance. On the one hand, a 20-year transmission planning horizon extends far enough into the future that transmission providers can proactively identify Long-Term Transmission Needs that could be met with more efficient or cost-effective Long-Term Regional Transmission Facilities; in contrast, as discussed below, a transmission planning horizon less than 20 years may limit transmission providers' ability to adequately plan for Long-Term Transmission Needs. Specifically, as described in the NOPR, a 20-year transmission planning horizon allows for more time between when a transmission facility is identified to meet a future transmission need, and when the transmission need materializes, allowing for sufficient time to identify, plan, obtain siting and permitting approval for, and construct Long-Term Regional Transmission Facilities. Moreover, as some commenters observe, several transmission providers, including MISO, SPP, and NYISO, already use a 20-year transmission planning horizon. On the other hand, based on the record before us, we find that there may be sufficient uncertainty with regard to system conditions and transmission needs beyond a 20-year horizon such that it may be challenging for transmission providers to forecast Long-Term Transmission Needs across that time period, especially for those transmission providers that do not presently conduct, and thus do not have experience with, long-term regional transmission planning. Accordingly, we decline to adopt a requirement to use a transmission planning horizon that exceeds 20 years. However, this does not preclude transmission providers from proposing to use a transmission planning horizon of more than 20 years.

346. We clarify that transmission providers must plan for the entire duration of the 20-year transmission planning horizon. Specifically, transmission providers must, among other requirements established in this

final order, develop and use Long-Term Scenarios to identify Long-Term Transmission Needs occurring in any period of the 20-year transmission planning horizon and to evaluate potential transmission solutions to those needs.

347. Certain commenters either misstate aspects of the proposed 20-year transmission planning horizon or request clarification regarding the horizon.⁸¹³ We specify that the transmission planning horizon starts at the beginning of the Long-Term Regional Transmission Planning cycle and ends 20 years from that date. The transmission planning horizon is not tied to the in-service date of any identified transmission solution; rather, potential transmission solutions are identified after identifying Long-Term Transmission Needs that manifest during the 20-year transmission planning horizon.

348. We disagree with commenters that assert that a 20-year transmission planning horizon could result in Long-Term Regional Transmission Planning based on speculative transmission needs⁸¹⁴ or, relatedly, that a 20-year transmission planning horizon is only appropriate if Long-Term Scenarios are not used to select Long-Term Regional Transmission Facilities.⁸¹⁵ We find these assertions to be unfounded. In fact, the Long-Term Regional Transmission Planning requirements adopted in this final order are designed to avoid over-building transmission in response to speculative transmission needs through a series of tools and safeguards, discussed at length above.⁸¹⁶ To highlight just one of these safeguards, as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final order, we require transmission providers to reevaluate certain previously selected Long-Term Regional Transmission Facilities in some circumstances to confirm that the Long-Term Regional Transmission Facility continues to meet the transmission providers' selection criteria. This reevaluation process will

⁸¹³ Kentucky Commission Chair Chandler Reply Comments at 2; National Grid Initial Comments at 12–13; PJM States Initial Comments at 3; PPL Initial Comments at 6; US Chamber of Commerce Initial Comments at 6.

⁸¹⁴ E.g., TANC Initial Comments at 10.

⁸¹⁵ NARUC Initial Comments at 5; Nebraska Commission Initial Comments at 3; Northwest and Intermountain Initial Comments at 7, 13; NRECA Initial Comments at 23, 29; NRG Initial Comments at 6–9, 14; Ohio Consumers Initial Comments at 20; see also PJM States Reply Comments at 9 (citing NARUC Initial Comments at 5).

⁸¹⁶ See *supra* Participation in Long-Term Regional Transmission Planning section.

help ensure that the continued selection of Long-Term Regional Transmission Facilities is based on the use of updated information regarding the existence of a Long-Term Transmission Need and the benefits that transmission providers expect a Long-Term Regional Transmission Facility to provide.

349. We disagree with commenters that assert that the Commission should adopt a shorter transmission planning horizon.⁸¹⁷ A transmission planning horizon of less than 20 years would fail to sufficiently capture Long-Term Transmission Needs given that at least some of the drivers of such needs extend up to 20 years into the future (e.g., many state laws include requirements to be met 15 to 20 years in the future). Additionally, a shorter minimum transmission planning horizon may not allow for sufficient time to develop Long-Term Regional Transmission Facilities with long lead-time requirements or to compare alternative transmission solutions to identify more efficient or cost-effective transmission solutions to meet Long-Term Transmission Needs.

350. We disagree with commenters that assert requiring a 20-year transmission planning horizon is incompatible with planning horizons used with state integrated resource planning.⁸¹⁸ In addition to the discussions in the Overall Need for Reform and Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning sections regarding state integrated resource planning, we note that regardless of the planning horizon used in a state integrated resource planning process, the results of that process can be incorporated into Long-Term Regional Transmission Planning to identify Long-Term Transmission Needs. In fact, as explained in State-Approved Utility Integrated Resource Plans and Expected Supply Obligations for Load-Serving Entities (Factor Category Three) section below, integrated resource plans are part of the Categories of Factors and thus, transmission providers must incorporate information on the load-serving entities' projected loads and resources over the planning horizon. The fact that a state integrated resource plan does not extend out a full 20 years—or extends further

⁸¹⁷ Exelon Initial Comments at 4, 7–8; Industrial Customers Initial Comments at 18; Mississippi Commission Initial Comments at 34; Nebraska Commission Initial Comments at 3–4; NRECA Initial Comments at 27–28; NRG Initial Comments at 6–9, 14; Omaha Public Power Initial Comments at 3–4; PJM Initial Comments at 5, 58–62; US Chamber of Commerce Initial Comments at 6; Utah Commission Initial Comments at 13.

⁸¹⁸ SERTP Sponsors Initial Comments at 21.

into the future—does not change the obligation for transmission providers to incorporate the information that is available over the 20-year transmission planning horizon.

351. In response to ISO–NE, and Policy Integrity,⁸¹⁹ the 20-year transmission planning horizon is distinct from the requirement to calculate benefits of an identified Long-Term Regional Transmission Facility over a minimum of 20 years from the estimated in-service date, as discussed in the Required Benefits section.

2. Frequency of Long-Term Scenario Revisions

a. NOPR Proposal

352. In the NOPR, the Commission proposed to require each transmission provider to develop Long-Term Scenarios at least every three years, by reassessing whether the data inputs and factors incorporated in the previously developed Long-Term Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors. The Commission also proposed to require that the development of Long-Term Scenarios be completed within three years, before the next three-year assessment commences.⁸²⁰

353. The Commission preliminarily found that a three-year frequency requirement balances the need of transmission providers to reassess changes in the resource mix and demand, as technology, markets, and policies have the potential to rapidly change, against the burden of developing Long-Term Scenarios that can take a year or longer to produce. The Commission stated that this three-year frequency requirement would allow transmission providers to identify new transmission needs driven by changes in the resource mix and demand during the interim years of the transmission planning period, and update previously identified transmission needs, if warranted.⁸²¹

b. Comments

i. Support for Frequency of Long-Term Scenario Revisions

354. Many commenters support the Commission's proposal to require transmission providers in each transmission planning region to develop Long-Term Scenarios at least every three years, by reassessing whether the data inputs and factors incorporated in the previously developed Long-Term

Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors.⁸²² Arizona Commission and Interwest state that the proposed three-year process aligns with their existing regional transmission planning processes.⁸²³ Several commenters assert that this proposal allows for Long-Term Scenarios to remain accurate and account for material technological, political, environmental, and operational developments in the energy industry,⁸²⁴ with some commenters indicating that past experience demonstrates that the energy industry is rapidly changing.⁸²⁵ For example, PIOs share that MISO recently recognized assumptions in its MISO Transmission Expansion Plan did not capture the rate of change for the region's fuel mix.⁸²⁶

355. Pennsylvania Commission states that routine reviews could update information and data, justify modifications to transmission plans, and reduce the risk of uneconomic transmission investments.⁸²⁷ ELCON notes that the proposed three-year reassessment provides the opportunity to consult recent data and update the probability of each scenario, which will produce better outcomes in the

transmission planning process.⁸²⁸ Joint Consumer Advocates state that long-term transmission plans must be revisited regularly and with sufficient frequency to ensure that they remain accurate and account for material developments.⁸²⁹ AEE states that triennial updates will provide a suitable amount of time for stakeholders to complete comprehensive studies while also ensuring that scenarios do not become stale as advanced energy technology deployment scales more rapidly and policy changes disrupt existing assumptions.⁸³⁰

356. Louisiana Commission avers that the proposed three-year reassessment will prevent transmission providers from ignoring changes that might better reflect future assumptions.⁸³¹ PIOs state that a three-year update will also help address issues that could occur if a transmission provider is too aggressive or conservative when defining scenarios.⁸³² DC and MD Offices of People's Counsel recommend that plans be updated every three years.⁸³³

357. Entergy and Interwest state that a three-year reassessment cycle balances the need for recent data and the time and resources needed to develop the updates.⁸³⁴ LADWP states that a rolling near-term planning horizon provides the long-term transmission planning process with up-to-date information without being too frequent.⁸³⁵ New Jersey Commission notes that reassessments more frequent than every three years would be overly burdensome.⁸³⁶ Similarly, Nebraska Commission states that a frequency shorter than every three years would require almost constant updates from transmission providers, which would drive up costs, while a frequency longer than three to five years could risk the underlying information becoming stale between revisions.⁸³⁷

358. Certain TDUs suggest that the Commission address concerns that a three-year review period would put significant strain on transmission provider resources by clarifying that three-year assessments would review the key drivers and assumptions behind

⁸²² ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8–9; AEP Initial Comments at 5, 8, 13–14; Amazon Initial Comments at 3; Arizona Commission Initial Comments at 4; BP Initial Comments at 4; Breakthrough Energy Supplemental Comments at 1; CAISO Initial Comments at 21; California Water Initial Comments at 15; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 13; DC and MD Offices of People's Counsel Initial Comments at 8; Entergy Initial Comments at 11; Idaho Power Initial Comments at 4; Interwest Initial Comments at 6–8; Joint Consumer Advocates Initial Comments at 8; Nevada Commission Initial Comments at 7; New England Offshore Wind Initial Comments at 2; New Jersey Commission Initial Comments at 11; NYISO Initial Comments at 18; Pacific Northwest State Agencies Initial Comments at 13–14; Pennsylvania Commission Initial Comments at 5; PG&E Initial Comments at 6; PIOs Initial Comments at 16; PJM Initial Comments at 5–6, 63; SEIA Initial Comments at 6; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

⁸²³ Arizona Commission Initial Comments at 3; Interwest Initial Comments at 6–8.

⁸²⁴ Advanced Energy Buyers Initial Comments at 7; California Water Initial Comments at 15; ELCON Initial Comments at 11; Joint Consumer Advocates at 8; PIOs Initial Comments at 17; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11.

⁸²⁵ Advanced Energy Buyers Initial Comments at 7; ELCON Initial Comments at 11.

⁸²⁶ PIOs Initial Comments at 16–17 (stating that MISO's prediction for changes in its fuel mix 15 years out in the MISO Transmission Expansion Plan 2020 Report had already materialized before that final report was published).

⁸²⁷ Pennsylvania Commission Initial Comments at 5.

⁸²⁸ ELCON Initial Comments at 11.

⁸²⁹ Joint Consumer Advocates Initial Comments at 8.

⁸³⁰ AEE Initial Comments at 8–9.

⁸³¹ Louisiana Commission Reply Comments at 9.

⁸³² PIOs Initial Comments at 17.

⁸³³ DC and MD Offices of People's Counsel Reply Comments at 2.

⁸³⁴ Entergy Initial Comments at 11; Interwest Initial Comments at 6.

⁸³⁵ LADWP Initial Comments at 3.

⁸³⁶ New Jersey Commission Initial Comments at 11.

⁸³⁷ Nebraska Commission Initial Comments at 4.

⁸¹⁹ ISO–NE Initial Comments at 23; Policy Integrity Initial Comments at 5.

⁸²⁰ NOPR, 179 FERC ¶ 61,028 at P 97.

⁸²¹ NOPR, 179 FERC ¶ 61,208 at P 99.

a transmission plan with updates as needed for material changes rather than a rerun of the full transmission planning process. In addition, Certain TDUs state that a three-year reassessment of initial transmission plans would result in more transparency and consideration of alternatives in the transmission planning process.⁸³⁸ In contrast, PJM requests that the Commission clarify that Long-Term Scenarios would be completely updated with new data, updated factors, and the best information available at least every three years, not merely partially reassessed. PJM also requests that the Commission clarify that scenario evaluations will not overlap, as re-runs are expensive, and a predictable three-year clock will make the process run smoothly.⁸³⁹

359. AEP requests that the Commission require all transmission planning regions to continuously follow the same, consistent three-year transmission planning cycles to align future efforts and ease burdens on transmission providers and developers operating in multiple transmission planning regions and to promote better coordination among regions concerning potential interregional transmission solutions.⁸⁴⁰

360. Southeast PIOs support the NOPR proposal to require transmission providers to reassess and revise Long-Term Scenarios every three years, arguing that it would synchronize with existing state processes and ensure that long-term regional transmission plans remain an up-to-date resource for state planning.⁸⁴¹ Similarly, Certain TDUs argue that a five-year transmission planning cycle is too long and that a three-year transmission planning cycle would be more likely to account for unforeseen changes, helping to prevent inefficient transmission development and balance planning for future needs with the need to quickly identify material changes to planning assumptions.⁸⁴²

ii. Concerns About Frequency of Long-Term Scenario Revisions

361. Some commenters urge the Commission to provide flexibility for transmission providers to determine the frequency at which they must develop Long-Term Scenarios by reassessing whether the data inputs and factors incorporated in their previously

developed Long-Term Scenarios need to be updated and then revising the Long-Term Scenarios as needed to reflect updated data inputs and factors.⁸⁴³ EEI requests that the Commission allow transmission providers in each transmission planning region to initiate a new Long-Term Scenario process in lieu of a refresh of old Long-Term Scenarios.⁸⁴⁴ California Commission and Omaha Public Power argue that requiring transmission providers to reassess and revise Long-Term Scenarios at least every three years will create a significant compliance burden without improving planning outcomes, such as forecast accuracy.⁸⁴⁵

362. MISO TOs argue that flexibility is warranted because MISO is already implementing Long-Term Regional Transmission Planning, as well as reassessing its data as needed.⁸⁴⁶ MISO states that the NOPR proposal is overly prescriptive, may not reflect stakeholder and regional needs, and could result in a compliance exercise without the prospect of transmission expansion.⁸⁴⁷ NESCOE and OMS suggest that the Commission require transmission providers to reassess Long-Term Scenarios at regular intervals but leave the timing of that reassessment to the transmission planning region.⁸⁴⁸ MISO also recommends that the Commission allow transmission providers to reuse Long-Term Scenarios as long as they update the relevant input data to reflect the latest available information.⁸⁴⁹

363. Duke asserts that the Commission should allow transmission planning regions to propose their own cycles to reassess and revise Long-Term Scenarios to meet the needs of the region, keep pace with markets and policies across the country, and align their processes with state integrated resource planning processes.⁸⁵⁰ Similarly, WIRES requests a variance to the proposed three-year scenario reassessment requirement because three years may be too short and could

potentially be disruptive or increase costs. WIRES further asks that the Commission clarify that transmission providers are not required to reassess previously approved transmission projects as part of their triennial review process.⁸⁵¹

364. Pacific Northwest State Agencies state that the Commission should set three years as a minimum and provide transmission planning regions with the flexibility to work with states to determine the appropriate schedule for developing Long-Term Scenarios.⁸⁵² Similarly, Vermont State Entities and Pennsylvania Commission argue that transmission planning regions should have the flexibility to conduct reassessments at intervals shorter than every three years.⁸⁵³

365. NYISO recommends that the final order should allow transmission planning regions to modify or add to their Long-Term Scenarios to account for changes that would significantly affect their analysis when they occur instead of waiting for the next transmission planning cycle. NYISO further requests that the Commission clarify that, if a transmission planning region requires more than three years to complete a given transmission planning cycle, it may extend the three-year time period. In addition, NYISO requests that the Commission permit transmission providers in each transmission planning region to commence the next Long-Term Regional Transmission Planning cycle using current information even if the prior transmission planning cycle is running in parallel. NYISO adds that the Commission should allow transmission planning regions to use their existing Long-Term Scenarios for the duration of a Long-Term Regional Transmission Planning cycle, even if it runs beyond three years, to avoid stopping and re-starting that cycle due to changes in circumstances.⁸⁵⁴

366. Some commenters raise concerns that the proposal to require development of Long-Term Scenarios at least every three years may create overlapping planning assessments and suggest ways to avoid that situation.⁸⁵⁵ ISO-NE states that the timeframe for Long-Term Regional Transmission Planning should account for all the elements of the process, such as implementing the process for selecting

⁸⁴³ Ameren Initial Comments at 12–13; American Municipal Power Initial Comments at 33; California Commission Initial Comments at 16; Duke Initial Comments at 11; ISO-NE Initial Comments at 24; MISO Initial Comments at 28–29; MISO TOs Initial Comments at 17; NARUC Initial Comments at 6–7; NESCOE Initial Comments at 25–26; OMS Initial Comments at 4–5; Pacific Northwest State Agencies Initial Comments at 15; Vermont State Entities Initial Comments at 5; WIRES Initial Comments at 7.

⁸⁴⁴ EEI Initial Comments at 12.

⁸⁴⁵ California Commission Initial Comments at 16; Omaha Public Power Initial Comments at 3.

⁸⁴⁶ MISO TOs Initial Comments at 17.

⁸⁴⁷ MISO Initial Comments at 28.

⁸⁴⁸ NESCOE Initial Comments at 25–26; OMS Initial Comments at 4–5.

⁸⁴⁹ MISO Initial Comments at 29.

⁸⁵⁰ Duke Initial Comments at 12.

⁸⁵¹ WIRES Initial Comments at 7.

⁸⁵² Pacific Northwest State Agencies Initial Comments at 15.

⁸⁵³ Pennsylvania Commission Initial Comments at 5; Vermont State Entities Initial Comments at 5.

⁸⁵⁴ NYISO Initial Comments at 19.

⁸⁵⁵ Eversource Initial Comments at 15; ISO-NE Initial Comments at 24; NESCOE Initial Comments at 26; PJM Initial Comments at 63.

⁸³⁸ Certain TDUs Reply Comments at 7.

⁸³⁹ PJM Initial Comments at 6, 63–64.

⁸⁴⁰ AEP Initial Comments at 5, 8, 13–14; AEP Reply Comments at 5.

⁸⁴¹ Southeast PIOs Reply Comments at 25.

⁸⁴² Certain TDUs Reply Comments at 5–6.

transmission solutions, before the next long-term study begins. ISO–NE indicates that this will allow subsequent Long-Term Regional Transmission Planning studies to account for the outcomes of the preceding transmission planning cycle and avoid unnecessary study overlap between cycles.⁸⁵⁶

367. Eversource suggests that the Commission require completion of project selection before the development of the next set of Long-Term Scenarios, arguing that it would undermine the project selection process if the current three-year Long-Term Scenario cycle fails to include selected transmission facilities from the prior three-year cycle.⁸⁵⁷

368. Similarly, NESCOE is concerned that the three-year Long-Term Scenario cycle requirement is inflexible and could interfere with existing procedures in New England. NESCOE states that ISO–NE’s longer-term transmission planning process requires that a planning process be concluded before a new one can begin, and that a request for a longer-term transmission study may be submitted to ISO–NE no earlier than six months after the conclusion of the prior study.⁸⁵⁸

369. Some commenters argue that requiring transmission providers to reassess and revise their Long-Term Scenarios every three years may be too frequent and costly, asserting that between every three and five years may be more appropriate.⁸⁵⁹ ITC avers that a three-year transmission planning cycle for Long-Term Regional Transmission Planning would exceed the capabilities of the transmission providers administering the process.⁸⁶⁰ Likewise, NRECA asserts that developing multiple Long-Term Scenarios and updating them every three years will require significant time and resources, as well as substantial changes in transmission planning throughout the country. NRECA asserts that existing power supply and transmission planning models employ different assumptions that cannot be used to prepare 20-year Long-Term Scenarios, much less update them every three years.⁸⁶¹

iii. Support for Different Frequency of Long-Term Scenario Revisions

370. Western PIOs support mandating a two-year timeframe for revision, as three years may be too long and therefore may miss important updated data inputs.⁸⁶²

371. Shell argues that the Commission should require transmission providers to reassess and revise their Long-Term Scenarios every five years, asserting that the proposal to use three years could create too much uncertainty and delay the development of renewable generation being developed to comply with state climate objectives and resource adequacy requirements in forward-looking capacity markets.⁸⁶³ Indicated PJM TOs argue that three years may be insufficient to perform relevant studies and recommend that the Commission provide transmission providers with the flexibility to adopt four- or five-year transmission planning cycles.⁸⁶⁴

372. Exelon argues that a three-year transmission planning cycle is too short, as it is unlikely that transmission needs will surface within three years, and that conducting a study so soon could create uncertainty that recently selected transmission projects will be revisited. Exelon instead recommends that the final order adopt a five-year transmission planning cycle requirement with a provision that requires transmission providers to initiate a new cycle sooner, with good reason, to better align with the time needed to permit and construct new transmission infrastructure.⁸⁶⁵

373. Similarly, PPL argues that a five-year transmission planning cycle will allow sufficient time for one transmission planning cycle to be completed before the subsequent cycle commences.⁸⁶⁶ Pine Gate states that a five-year transmission planning cycle is warranted given the size and complexity of transmission planning regions and the time needed to receive and incorporate stakeholder feedback and to achieve consensus on cost allocation. Pine Gate further notes that a five-year transmission planning cycle would more closely align the results of Long-Term Regional Transmission Planning with the time horizons for reliability planning and other transmission planning processes.⁸⁶⁷

374. SPP argues in favor of the update procedures in its current transmission

planning processes rather than the three-year schedule for updating Long-Term Scenarios proposed in the NOPR. SPP states that it performs a 20-year assessment that incorporates Long-Term Scenarios at least once every five years and that, on an annual basis, SPP assesses data inputs and factors incorporated into the assessment.⁸⁶⁸

iv. Miscellaneous Comments

375. Several commenters state that the Commission should regularly review transmission planning processes and assumptions to account for new developments.⁸⁶⁹ Pattern Energy states that the best way to make 20-year transmission plans useful is for their outputs to be fed into near-term (*i.e.*, five-to-seven-year horizon) transmission planning activities.⁸⁷⁰

376. ELCON recommends that the Commission hold a technical conference after the first three-year reassessment period for Long-Term Scenarios to allow transmission providers to offer their experiences with and best practices for Long-Term Regional Transmission Planning.⁸⁷¹

c. Commission Determination

377. We modify the NOPR proposal to require transmission providers in each transmission planning region to reassess and revise the Long-Term Scenarios that they use in Long-Term Regional Transmission Planning at least once every five years. In implementing this requirement, transmission providers in each transmission planning region must reassess whether the data inputs and factors incorporated in previously developed Long-Term Scenarios need to be updated and then revise those Long-Term Scenarios, as needed, to reflect updated data inputs and factors. At the outset of a Long-Term Regional Transmission Planning cycle, transmission providers may develop the new Long-Term Scenarios either by crafting entirely new Long-Term Scenarios, or by updating the data inputs and factors of previously developed Long-Term Scenarios.

378. To assist transmission providers in implementing the requirement to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years, we clarify that the process, which begins with the development of Long-Term Scenarios using best available data inputs, and

⁸⁵⁶ ISO–NE Initial Comments at 24.

⁸⁵⁷ Eversource Initial Comments at 15.

⁸⁵⁸ NESCOE Initial Comments at 26.

⁸⁵⁹ ACEG Initial Comments at 7, 25; Breakthrough Energy Initial Comments at 12–13; EEI Initial Comments at 12; Indicated PJM TOs Initial Comments at 11–12; ITC Initial Comments at 5, 9–11; Pine Gate Initial Comments at 19–20.

⁸⁶⁰ ITC Initial Comments at 10.

⁸⁶¹ NRECA Initial Comments at 23 (citing GDS Assocs., Report, at 8–10 (Aug. 17, 2022)).

⁸⁶² Western PIOs Initial Comments at 30.

⁸⁶³ Shell Initial Comments at 18–19.

⁸⁶⁴ Indicated PJM TOs Initial Comments at 11–12.

⁸⁶⁵ Exelon Initial Comments at 9.

⁸⁶⁶ PPL Initial Comments at 6.

⁸⁶⁷ Pine Gate Initial Comments at 20–21.

⁸⁶⁸ SPP Initial Comments at 5–6.

⁸⁶⁹ Clean Energy Buyers Initial Comments at 13; SREA Reply Comments at 26–27.

⁸⁷⁰ Pattern Energy Initial Comments at 22.

⁸⁷¹ ELCON Initial Comments at 11.

proceeds to identifying Long-Term Transmission Needs, measuring the benefits of Long-Term Regional Transmission Facilities to address those needs, and evaluating and deciding whether to select Long-Term Regional Transmission Facilities (collectively, the Long-Term Regional Transmission Planning cycle),⁸⁷² must conclude at a date that is no later than five years after the date that it began.

379. While we find that the record supports a five-year interval before new Long-Term Scenarios must be developed, we also conclude that transmission providers should not need the full five-year period to reach the point in Long-Term Regional Transmission Planning at which they decide whether to select Long-Term Regional Transmission Facilities that they have evaluated. Accordingly, we require transmission providers to complete the steps of the Long-Term Regional Transmission Planning cycle and determine whether to select Long-Term Regional Transmission Facilities no later than three years from the date when the Long-Term Regional Transmission Planning cycle began.⁸⁷³ Specifically, we find the record sufficient time for transmission providers to develop Long-Term Scenarios, identify Long-Term Transmission Needs, measure the benefits of Long-Term Regional Transmission Facilities to address those needs, and evaluate and decide whether to select Long-Term Regional Transmission Facilities.⁸⁷⁴ At the same

time, we are persuaded by commenters' concerns that requiring the Long-Term Regional Transmission Planning cycle to repeat at three-year intervals could be administratively burdensome, and that the benefit of updating Long-Term Scenarios every three years may not outweigh those additional burdens.⁸⁷⁵ We therefore find that requiring selection decisions to occur within three years of commencing a Long-Term Regional Transmission Planning cycle, while allowing as long as five years between the commencement of each planning cycle, strikes an appropriate balance by ensuring timely identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities, while balancing the administrative burden associated with updating the Long-Term Scenarios that form the basis for Long-Term Regional Transmission Planning during each planning cycle.⁸⁷⁶

380. We find that requiring transmission providers to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years is necessary to ensure that the Long-Term Scenarios accurately reflect factors that may change over the five-year time span, such as changes in technology, load forecasts, or Federal, federally-recognized Tribal, state, or local laws. Furthermore, regular scenario reassessment and revision may also address some of the uncertainty associated with Long-Term Regional Transmission Planning over a 20-year transmission planning horizon that some commenters assert may result in under-building or over-building

transmission facilities.⁸⁷⁷ As discussed below in the Specificity of Data Inputs section, nothing in this final order prohibits transmission providers from updating the inputs used to inform Long-Term Scenarios during a Long-Term Regional Transmission Planning cycle.

381. As discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final order, transmission providers must designate a point in the evaluation process at which they will make a decision to either select or not select the relevant Long-Term Regional Transmission Facility (or portfolio of such Facilities). Further, we clarify that transmission providers must conclude a Long-Term Regional Transmission Planning cycle before developing Long-Term Scenarios at the beginning of the next Long-Term Regional Transmission Planning cycle. Given that, as we state directly above, nothing in this final order prevents transmission providers from evaluating and selecting additional Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle and before the next five-year Long-Term Regional Transmission Planning cycle begins, we further find that transmission providers must designate the point in time or action that concludes a Long-Term Regional Transmission Planning cycle. Such designation will ensure transparency regarding whether the transmission providers are engaging in the evaluation and selection of additional Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle.

382. Some commenters express concern that the proposal to reassess Long-Term Scenarios in concurrent Long-Term Regional Transmission Planning cycles would create uncertainty as to which cycle produced the controlling outcome and would burden stakeholders (e.g., requiring them to provide input on the development of Long-Term Scenarios for the next Long-Term Regional Transmission Planning cycle while also requiring them to provide input on Long-Term Regional Transmission Facilities being considered for selection from the previous Long-Term Regional Transmission Planning cycle).⁸⁷⁸ By providing for a period of up to two years between the date by which transmission

⁸⁷² The Long-Term Regional Transmission Planning cycle encompasses all components of Long-Term Regional Transmission Planning, including each of these foundational steps.

⁸⁷³ To be clear, nothing in this final order prevents transmission providers from evaluating and selecting *additional* Long-Term Regional Transmission Facilities after year three of the Long-Term Regional Transmission Planning cycle and before the next five-year Long-Term Regional Transmission Planning cycle begins. However, if Long-Term Regional Transmission Facilities are selected at year three of the Long-Term Regional Transmission Planning cycle, those same Long-Term Regional Transmission Facilities cannot be de-selected during the remainder of the current five-year planning cycle.

⁸⁷⁴ See ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 7; AEE Initial Comments at 8–9; AEP Initial Comments at 5, 8, 13–14; Amazon Initial Comments at 3; Arizona Commission Initial Comments at 4; BP Initial Comments at 4; Breakthrough Energy Supplemental Comments at 1; CAISO Initial Comments at 21; California Water Initial Comments at 15; Clean Energy Associations Initial Comments at 10; Clean Energy Buyers Initial Comments at 13; DC and MD Offices of People's Counsel Initial Comments at 8; Entergy Initial Comments at 11; Idaho Power Initial Comments at 4; Interwest Initial Comments at 6–8; Joint Consumer Advocates Initial Comments at 8; Nevada Commission Initial Comments at 7; New England Offshore Wind Initial Comments at 2; New

Jersey Commission Initial Comments at 11; NYISO Initial Comments at 18; Pacific Northwest State Agencies Initial Comments at 13–14; Pennsylvania Commission Initial Comments at 5; PG&E Initial Comments at 6; PIOs Initial Comments at 16; PJM Initial Comments at 5–6, 63; SEIA Initial Comments at 6; SPP Market Monitor Initial Comments at 6; US DOE Initial Comments at 11; Vermont State Entities Initial Comments at 5; WE ACT Initial Comments at 3.

⁸⁷⁵ See Ameren Initial Comments at 12–13; American Municipal Power Initial Comments at 33; California Commission Initial Comments at 16; Duke Initial Comments at 11; ISO–NE Initial Comments at 24; MISO Initial Comments at 28–29; MISO TOs Initial Comments at 17; NARUC Initial Comments at 6–7; NESCOE Initial Comments at 25–26; OMS Initial Comments at 4–5; Pacific Northwest State Agencies Initial Comments at 15; Vermont State Entities Initial Comments at 5; WIRES Initial Comments at 7.

⁸⁷⁶ Accordingly, we decline NYISO's request to clarify that the transmission provider may extend the transmission planning cycle. As explained, we find that three years provides sufficient time to complete the actions necessary to make selection decisions.

⁸⁷⁷ Industrial Customers Initial Comments at 15–16, 19–21; NRECA Initial Comments at 18–19, 28; Vistra Initial Comments at 7.

⁸⁷⁸ Eversource Initial Comments at 15; ISO–NE Initial Comments at 24; NESCOE Initial Comments at 26.

providers are required to make a decision to select or not select Long-Term Regional Transmission Facilities and the date by which the next Long-Term Regional Transmission Planning cycle must commence, and by clarifying that transmission providers must conclude one Long-Term Regional Transmission Planning cycle before another begins, this final order will appropriately minimize confusion regarding overlap between planning assessments. Specifically, this clarification will allow transmission providers to use in subsequent Long-Term Regional Transmission Planning cycles updated base or reference cases that include all Long-Term Regional Transmission Facilities that were selected in a previous Long-Term Regional Transmission Planning cycle, including those not yet in service. We find that including the selected Long-Term Regional Transmission Facilities in subsequent Long-Term Regional Transmission Planning cycles will improve the accuracy of Long-Term Regional Transmission Planning.

383. In response to WIRES's request,⁸⁷⁹ we clarify that transmission providers need not routinely reevaluate selected Long-Term Regional Transmission Facilities. However, we note that, as discussed further in the Evaluation and Selection of Long-Term Regional Transmission Facilities section below, we require transmission providers to reevaluate previously selected Long-Term Regional Transmission Facilities in certain specified circumstances.

384. Given that we are requiring transmission providers in each transmission planning region to reassess and revise Long-Term Scenarios used in Long-Term Regional Transmission Planning at least once every five years, thus establishing the maximum length of the Long-Term Regional Transmission Planning cycle, we affirm that to the extent that transmission providers believe that a shorter Long-Term Regional Transmission Planning cycle is appropriate for their transmission planning region and circumstances, they may propose on compliance to conduct Long-Term Regional Transmission Planning more frequently than every five years.

385. We find AEP's request to require all transmission planning regions to follow the same-length transmission planning cycles is beyond the scope of this proceeding.⁸⁸⁰ In the NOPR, we proposed frequency requirements

related to the Long-Term Regional Transmission Planning cycles but did not propose a requirement for transmission providers to align their regional transmission planning cycles with those of the transmission providers in neighboring transmission planning regions.

386. While we do not establish a technical conference after the first Long-Term Regional Transmission Planning cycle, as ELCON requests,⁸⁸¹ the Commission has discretion to conduct additional proceedings at a future date if it finds they are warranted.

3. Categories of Factors

a. Requirement To Incorporate Categories of Factors

i. NOPR Proposal

387. In the NOPR, the Commission proposed to require transmission providers to incorporate specific categories of factors in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning.⁸⁸² Specifically, the Commission proposed to require transmission providers to incorporate, at a minimum, the following categories of factors in the development of Long-Term Scenarios: (1) Federal, state, and local laws and regulations that affect the future resource mix and demand;⁸⁸³ (2) Federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load-serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and Federal, state, and local goals⁸⁸⁴ that affect the future resource mix and demand.⁸⁸⁵

388. The Commission preliminarily found that incorporating, at a minimum, these categories of factors in the development of Long-Term Scenarios is appropriate because these categories of factors affect the future resource mix and demand, and their incorporation in

Long-Term Scenarios is therefore essential to identifying transmission needs driven by changes in the resource mix and demand through Long-Term Regional Transmission Planning.⁸⁸⁶ To the extent that transmission providers in a transmission planning region would like to incorporate additional categories of factors in the development of Long-Term Scenarios, the Commission proposed to require that they demonstrate on compliance with any final order that the incorporation of more than the minimum categories is consistent with or superior to any final order in this proceeding.⁸⁸⁷

389. Also, as discussed in the Coordination of Regional Transmission Planning and Generator Interconnection Processes section of the NOPR,⁸⁸⁸ the Commission proposed to require that transmission providers consider in their Long-Term Regional Transmission Planning regional transmission facilities that address interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s). The Commission proposed to require that transmission providers incorporate the specific interconnection-related needs identified through that proposed reform, in addition to one or more factors that more generally characterize generator interconnection withdrawals, as a factor in the generator interconnection requests and withdrawals category of factors in their development of Long-Term Scenarios.⁸⁸⁹

390. The Commission explained that incorporation of the categories of factors set forth above in developing Long-Term Scenarios would help facilitate the identification of transmission needs driven by changes in the resource mix and demand, which the Commission preliminarily found was necessary to ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates. The Commission explained that absent a requirement to incorporate these categories of factors in the development of Long-Term Scenarios, transmission providers may not incorporate known inputs that likely will affect the future resource mix and demand. Additionally, the Commission explained that transmission providers may not adequately identify transmission needs

⁸⁸¹ ELCON Initial Comments at 11.

⁸⁸² NOPR, 179 FERC ¶ 61,028 at PP 104–112.

⁸⁸³ *Id.* P 104 n.189. The Commission explained that “state or federal laws or regulations” meant “enacted statutes (*i.e.*, passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state, municipality, or at the federal level.”

⁸⁸⁴ *Id.* P 104 n.195. The Commission explained that “goal” meant “any commitment or statement expressed in writing that is not a law or regulation.”

⁸⁸⁵ *Id.* P 104.

⁸⁸⁶ *Id.* P 105.

⁸⁸⁷ *Id.*

⁸⁸⁸ *Id.* PP 166–174.

⁸⁸⁹ *Id.* P 107.

⁸⁷⁹ WIRES Initial Comments at 7.

⁸⁸⁰ AEP Initial Comments at 5, 8, 14; AEP Reply Comments at 5.

driven by changes in the resource mix and demand and evaluate the potential benefits of regional transmission facilities that may more efficiently or cost-effectively meet such needs. The Commission stated that, as an additional benefit, this requirement would provide clarity to transmission providers and stakeholders regarding which factors must be considered in scenario development.⁸⁹⁰

ii. Comments

(a) Requirement To Incorporate Categories of Factors

391. A number of commenters support the proposal to require transmission providers to incorporate in their development of Long-Term Scenarios the seven specific categories of factors identified in the NOPR.⁸⁹¹ Georgia Commission asserts that these categories of factors adequately capture the factors expected to drive changes in the resource mix and demand,⁸⁹² and APPA states that they reflect potential drivers of the need for new transmission.⁸⁹³

392. AEE asks that the Commission clarify that consideration of each factor is mandatory, arguing that failing to take into account any of the seven listed categories of factors would risk under-investment in regional transmission facilities, which could result in unjust and unreasonable rates.⁸⁹⁴ Evergreen Action and Pine Gate assert that the Commission should require that the seven factors are “incorporated” instead of “considered” in order to make clear that incorporation is not optional.⁸⁹⁵ Otherwise, Pine Gate states, transmission providers may ignore certain categories relevant and critical to

identifying needed transmission infrastructure.⁸⁹⁶

393. DC and MD Offices of People’s Counsel also urge the Commission to require that all seven factor categories listed in the NOPR be included in Long-Term Scenarios.⁸⁹⁷ DC and MD Offices of People’s Counsel and ACEG state that the flexibility proposed in the NOPR could give transmission providers the option of not considering the last four factor categories.⁸⁹⁸ SEIA recommends that the Commission establish guidelines on the information used to determine factors in the last four factor categories to ensure some level of certainty in how they are reflected in Long-Term Scenarios.⁸⁹⁹

394. Clean Energy Buyers support the NOPR proposal, arguing that requiring uniform categories of factors across transmission planning regions could promote efficiency and interregional coordination.⁹⁰⁰ Southeast PIOs argue that broader consideration of resource trends and other transmission drivers through comprehensive scenarios will inform the decision-making of state authorities tasked with approving transmission facilities.⁹⁰¹ Indicated US Senators and Representatives express general support for proactive transmission planning that considers a broad range of factors.⁹⁰²

395. MISO TOs, MISO, and OMS state that existing MISO processes already identify and consider the proposed categories of factors to develop scenarios for transmission planning.⁹⁰³ MISO TOs further claim that there is no need to require that MISO consider additional factors.⁹⁰⁴ OMS supports the NOPR’s proposed requirements as to the minimum categories of factors and asserts that the categories of factors proposed in the NOPR are all included in MISO’s existing transmission planning processes.⁹⁰⁵

396. Some commenters support the NOPR proposal because they note that it provides transmission providers with flexibility as to the specific factors they incorporate into their development of

Long-Term Scenarios, as well as how they incorporate those factors.⁹⁰⁶

397. A few commenters support the NOPR proposal to allow transmission providers to incorporate additional categories of factors if they can demonstrate that doing so is consistent with or superior to the final order.⁹⁰⁷ Specifically, AEE states that the Commission should clarify that transmission providers can propose to consider other categories of factors.⁹⁰⁸

398. Pattern Energy states that the Commission should provide examples of how the categories of factors and their associated sensitivities may be modeled to ensure that each Long-Term Scenario is useful for Long-Term Regional Transmission Planning. For example, Pattern Energy asks whether the different scenarios alter the various assumptions for each (or some) of the factors. Alternatively, Pattern Energy asks whether the assumptions remained fixed across scenarios and different scenarios are designed to evaluate different transmission solutions.⁹⁰⁹

(b) Requests for Flexibility

399. Some commenters argue that the Commission should give transmission providers more flexibility to determine the appropriate categories of factors or individual factors to include in their development of Long-Term Scenarios.⁹¹⁰ NESCOE contends that providing flexibility would be consistent with the Commission’s approach in Order No. 1000, where it did not require the identification of transmission needs driven by any particular Public Policy Requirements.⁹¹¹ PG&E argues that the Commission should allow transmission providers to experiment with how they define scenarios and factors to best reflect the policy and planning environments of their transmission

⁸⁹⁰ *Id.* P 111.

⁸⁹¹ ACEG Initial Comments at 7; Advanced Energy Buyers Initial Comments at 5; AEE Initial Comments at 9–10; Breakthrough Energy Initial Comments at 14; Breakthrough Energy Supplemental Comments at 1; City of New York Initial Comments at 7; Clean Energy Associations Initial Comments at 10–11; Clean Energy Buyers Initial Comments at 14–15; ELCON Initial Comments at 12; Eversource Initial Comments at 16–17; Illinois Commission Initial Comments at 4–5; Kansas Commission Initial Comments at 14–15; Nevada Commission Initial Comments at 8; Northwest and Intermountain Initial Comments at 13; NRECA Initial Comments at 30; OMS Initial Comments at 6; Ørsted Initial Comments at 6; Pacific Northwest State Agencies Initial Comments at 14; PG&E Initial Comments at 6; Pine Gate Initial Comments at 22; PIOs Initial Comments at 17–18; PJM Initial Comments at 6, 64; SEIA Initial Comments at 7; Southeast PIOs Initial Comments at 44–45; US DOE Initial Comments at 11–12.

⁸⁹² Georgia Commission Initial Comments at 4.

⁸⁹³ APPA Initial Comments at 27–28.

⁸⁹⁴ AEE Initial Comments at 10.

⁸⁹⁵ Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 22–23.

⁸⁹⁶ Pine Gate Initial Comments at 22.

⁸⁹⁷ DC and MD Offices of People’s Counsel Initial Comments at 11–12.

⁸⁹⁸ ACEG Initial Comments at 28; DC and MD Offices of People’s Counsel Initial Comments at 11.

⁸⁹⁹ SEIA Initial Comments at 9–10.

⁹⁰⁰ Clean Energy Buyers Initial Comments at 14–15.

⁹⁰¹ Southeast PIOs Reply Comments at 26.

⁹⁰² Indicated US Senators and Representatives Initial Comments at 1.

⁹⁰³ MISO Initial Comments at 34–35; MISO TOs Initial Comments at 18; OMS Initial Comments at 6.

⁹⁰⁴ MISO TOs Initial Comments at 18.

⁹⁰⁵ OMS Initial Comments at 6.

⁹⁰⁶ Exelon Initial Comments at 10–11; Georgia Commission Initial Comments at 4; Illinois Commission Initial Comments at 7; NEPOOL Initial Comments at 7.

⁹⁰⁷ Acadia Center and CLF Initial Comments at 9; Clean Energy Buyers Initial Comments at 14–15; ELCON Initial Comments at 12; NESCOE Initial Comments at 27; US DOE Initial Comments at 11–12.

⁹⁰⁸ AEE Initial Comments at 10.

⁹⁰⁹ Pattern Energy Initial Comments at 24.

⁹¹⁰ Alabama Commission Initial Comments at 7; APPA Initial Comments at 27–28; Dominion Initial Comments at 25; Indicated PJM TOs Initial Comments at 8–9; MISO Initial Comments at 29; NARUC Initial Comments at 8–9; New York TOs Initial Comments at 11–12; NYISO Initial Comments at 8, 20; Pennsylvania Commission Initial Comments at 5–6; PG&E Initial Comments at 7.

⁹¹¹ NESCOE Initial Comments at 27–28 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 207).

planning regions.⁹¹² EEI notes that not all of the factors listed in the NOPR may be relevant for all transmission planning regions during every long-term assessment and explains that private sector, Federal, state, and local public policy goals may diverge or conflict, especially in multi-state regions.⁹¹³

400. ISO-NE requests that the Commission provide transmission providers with flexibility in the consideration of factors for inclusion in each scenario, noting that the factors may vary from study to study depending on the study objectives. Specifically, ISO-NE argues that the Commission should not require that each Long-Term Scenario account for and consistently reflect the first three categories of factors: Federal, state, and local laws and regulations on the future resource mix, decarbonization and electrification, and state-approved integrated resource plans. ISO-NE emphasizes that the Commission should not require local laws to be consistently reflected in and accounted for in Long-Term Scenarios. ISO-NE argues that, in addition to being too prescriptive, such a requirement would introduce unnecessary and substantial administrative burdens and compliance risks with the possibility for inadvertent exclusion of a required law, regulation, or integrated resource plan. Moreover, ISO-NE contends, it would unnecessarily prevent testing of variations with these categories of factors, limiting the usefulness of scenario analysis.⁹¹⁴

401. Idaho Commission and Idaho Power argue that the NOPR proposal is too prescriptive.⁹¹⁵ PJM advises the Commission not to include too many inflexible details in the implementation of the factors.⁹¹⁶ However, PJM generally supports the NOPR proposal to create seven factors that should guide the development of scenarios with some additions and revisions.⁹¹⁷

402. NYISO states that the Commission should not prescribe specific categories of factors that transmission providers must use and instead should allow each transmission planning region, in coordination with state entities and stakeholders, to determine to what extent and how the seven categories of factors should be applied.⁹¹⁸ SEIA disagrees, asserting that each proposed category of factors is broad enough to reflect regional

differences within the category, but suggests that the Commission provide flexibility on implementation details. SEIA explains that the categories of factors do not set forth specific requirements on how much weight each factor should have in each Long-Term Scenario, what generation mix will result from the mix of factors, or what models to use. SEIA states that the Commission should allow transmission providers to include these implementation details in their manuals.⁹¹⁹

403. Some commenters express support for some or all of the proposed categories of factors but request that the Commission provide transmission providers with flexibility in how they incorporate the factors into their development of Long-Term Scenarios.⁹²⁰ For example, TANC requests that the Commission allow transmission planning regions, in consultation with stakeholders, to exclude some of the proposed factors (*i.e.*, regulatory and corporate goals or technology trends) from their development of Long-Term Scenarios.⁹²¹ TANC also advocates that the Commission should allow transmission planning regions to determine the manner in which other factors, namely trends, resource requirements, generator interconnection requests, and withdrawals, are incorporated in regional transmission planning studies. Although SPP states that most of the categories of factors are appropriate, it contends that requiring the listed factors to be incorporated, rather than considered, in development of Long-Term Scenarios could overburden the process.⁹²²

404. NEPOOL states that the categories of factors identified in the NOPR seem generic enough to allow implementation despite regional differences or changes in circumstances over time but contends that the Commission should carefully consider different market structures and potential changes to state policies to ensure that any requirement accommodates regional differences.⁹²³ Pine Gate further requests clarification as to the degree of flexibility that the Commission will grant to transmission providers in how

they incorporate each factor into Long-Term Scenarios.⁹²⁴

(c) Concerns With the Requirement To Incorporate Categories of Factors

405. Large Public Power argues that the NOPR proposal ignores the Commission's fundamental responsibility to facilitate planning to meet the needs of load-serving entities, as well as Congress' recognition that load-serving entities themselves have a fundamental obligation to build transmission to meet their load.⁹²⁵ Large Public Power asserts that the NOPR proposal to establish factors that look more broadly than the Commission's core obligations under the FPA threatens to undermine the needs of load-serving entities and their customers.⁹²⁶ Further, Large Public Power contends that the Commission has no authority to direct the development of transmission facilities.⁹²⁷ Similarly, some commenters voice concerns with the use of categories of factors to direct transmission investment.⁹²⁸ Louisiana Commission states that the incorporation of speculative factors would result in a large-scale transmission build-out to accommodate the policy preference of some, at the cost of all.⁹²⁹

406. Undersigned States claim that the proposed requirement that each Long-Term Scenario "incorporate and be consistent" with certain factors does not address potentially irresolvable conflicts over how certain factors affect the future resource mix and demand.⁹³⁰ PPL criticizes the NOPR for failing to explain how to translate the proposed factors into usable assumptions that can feed into transmission planning models, leading to increased uncertainty for transmission developers and greater difficulty in financing transmission projects or gaining siting approval.⁹³¹

(d) Alternative Frameworks

407. Other commenters propose alternative frameworks for incorporating factors in the development of Long-Term Scenarios. PPL believes that the Commission's proposed categories of factors are largely overlapping and can

⁹²⁴ Pine Gate Initial Comments at 22–23.

⁹²⁵ Large Public Power Initial Comments at 19–20 (citing 16 U.S.C. 824q, (e)); *see also* NRECA Initial Comments at 17–18 (quoting 16 U.S.C. 824q(b)(4)), 19–20).

⁹²⁶ Large Public Power Initial Comments at 20–21.

⁹²⁷ *Id.* at 11 (citing 16 U.S.C. 824o(i)(2)).

⁹²⁸ Industrial Customers Initial Comments at 11;

Louisiana Commission Initial Comments at 17–19

⁹²⁹ Louisiana Commission Initial Comments at 17–19.

⁹³⁰ Undersigned States Initial Comments at 3.

⁹³¹ PPL Initial Comments at 8.

⁹¹² PG&E Initial Comments at 7.

⁹¹³ EEI Initial Comments at 12–13.

⁹¹⁴ ISO-NE Initial Comments at 26–27.

⁹¹⁵ Idaho Commission Initial Comments at 3; Idaho Power Initial Comments at 5.

⁹¹⁶ PJM Initial Comments at 67.

⁹¹⁷ *Id.* at 6, 64.

⁹¹⁸ NYISO Initial Comments at 8, 20.

⁹¹⁹ SEIA Reply Comments at 3–4.

⁹²⁰ Ameren Initial Comments at 9–12; APPA Initial Comments at 27–28; Arizona Commission Initial Comments at 5; Eversource Initial Comments at 16–17; ISO-NE Initial Comments at 26; LADWP Initial Comments at 3; TANC Initial Comments at 9–10.

⁹²¹ TANC Initial Comments at 9–10.

⁹²² SPP Initial Comments at 7–8.

⁹²³ NEPOOL Initial Comments at 7.

be summarized and replaced by a single factor: reasonable expectations regarding the future resource mix and demand.⁹³² ENGIE suggests that, because the Commission's proposed factors may be too numerous for transmission providers to model, certain factors (*i.e.*, laws, regulations, and announced retirements) should be fixed while others are varied or studied as sensitivities (*i.e.*, costs, demand, and resource development trends).⁹³³ PIOs state that the Commission must set minimum requirements for some factors, asserting that there is broad support for minimum requirements.⁹³⁴

408. GridLab contends that the Commission's proposal to require that transmission providers incorporate specific categories of factors in the development of Long-Term Scenarios cannot be enforced and that such broad factors will not change investment outcomes. GridLab states that the proposed list of factors are a helpful minimum standard and recommends that the Commission focus on whether transmission providers have meaningfully incorporated them into Long-Term Regional Transmission Planning.⁹³⁵ Further, GridLab avers that local laws and regulations and corporate commitments are difficult to incorporate into Long-Term Regional Transmission Planning in a bottom-up, meaningful way.⁹³⁶ As an alternative, GridLab suggests that transmission providers could use aggregate assumptions and indicative scenario design and allow state and local agencies, as well as other stakeholders, to provide inputs into scenario development, and then evaluate whether the resulting scenarios are consistent with state, local, and corporate commitments.⁹³⁷

iii. Commission Determination

409. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate the seven specific categories of factors proposed in the NOPR, as modified in this final order, in the development of Long-Term Scenarios. Specifically, as discussed in more detail below, transmission providers must incorporate in the development of Long-Term Scenarios: (1) Federal, federally-recognized Tribal,⁹³⁸ state, and local

laws and regulations affecting the resource mix and demand; (2) Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.⁹³⁹ We address each of these categories of factors in the Specific Categories of Factors determination section below.

410. We find that existing regional transmission planning requirements fail to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs.⁹⁴⁰ Many commenters in this proceeding, even some that may oppose the prescriptiveness of the requirement or otherwise request more flexibility in how transmission providers account for factors affecting Long-Term Transmission Needs,⁹⁴¹ generally agree that the categories of factors outlined in the NOPR account for many of the known determinants of such needs. We find that incorporating the seven categories of factors in the development of Long-Term Scenarios is necessary because these categories of factors are essential to identifying Long-Term Transmission Needs. Further, we find that requiring transmission providers to incorporate the enumerated categories of factors in Long-Term Regional Transmission Planning will help to ensure that transmission providers are accounting for known and identifiable drivers of Long-Term Transmission Needs.

411. We are not persuaded by commenters' arguments that certain of the categories of factors may not be relevant in certain transmission planning regions and therefore that transmission providers should not be required to incorporate those categories

of factors in the development of Long-Term Scenarios.⁹⁴² We decline to allow transmission providers to exclude some of the proposed categories of factors from being incorporated in the development of Long-Term Scenarios, as certain commenters request, because we conclude that each category of factors includes important determinants of Long-Term Transmission Needs. We are concerned that not requiring incorporation of all of the proposed categories of factors in Long-Term Scenarios would increase the likelihood that transmission providers will continue to underestimate—or omit entirely—certain known determinants of Long-Term Transmission Needs in their regional transmission planning processes.

412. In response to AEE's request, we affirm that the seven categories of factors adopted in this final order are the minimum set of known determinants of Long-Term Transmission Needs that transmission providers must incorporate into the development of their Long-Term Scenarios, and we decline to adopt the NOPR proposal to require transmission providers to demonstrate on compliance that the incorporation of additional categories of factors is consistent with or superior to any final order in this proceeding.⁹⁴³ Transmission providers may be aware of additional categories of factors beyond those adopted in this final order that drive Long-Term Transmission Needs and, thus, should be incorporated into the development of Long-Term Scenarios. While transmission providers may incorporate additional categories of factors into the development of Long-Term Scenarios, we require in this final order that each Long-Term Scenario remains plausible, as discussed further below.

413. We clarify that incorporating each category of factors into the development of Long-Term Scenarios means more than merely considering each category of factors in the development of Long-Term Scenarios.⁹⁴⁴ Incorporating a category of factors in the development of Long-Term Scenarios means that transmission providers must use factors in the category, for each factor individually or collectively, to determine the assumptions that will be used in the development of Long-Term Scenarios. Incorporating a category of factors into the development of Long-Term

⁹³² *Id.* at 7.

⁹³³ ENGIE Initial Comments at 3.

⁹³⁴ PIOs Reply Comments at 10.

⁹³⁵ GridLab Initial Comments at 21–22.

⁹³⁶ *Id.* at 22.

⁹³⁷ *Id.*

⁹³⁸ We emphasize that we are requiring transmission providers to incorporate laws and regulations into Long-Term Scenario development. As noted earlier, while we are providing this

opportunity for federally-recognized Tribes to voluntarily participate, we are not imposing any requirements on them to participate.

⁹³⁹ Modifications to the title of Factor Categories One, Two, Four, and Seven are discussed in the Specific Categories of Factors determination section.

⁹⁴⁰ NOPR, 179 FERC ¶ 61,028 at PP 50–51.

⁹⁴¹ *See, e.g.*, EEI Initial Comments at 12–13; PJM Initial Comments at 64–67.

⁹⁴² *See, e.g.*, EEI Initial Comments at 12–13; SPP Initial Comments at 7–8.

⁹⁴³ AEE Initial Comments at 10.

⁹⁴⁴ Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 22–23.

Scenarios does not require exacting precision; transmission providers may generalize how all of the discrete factors in a category of factors will, in the aggregate, affect the development of Long-Term Scenarios.⁹⁴⁵ However, we expect that similar factors (or groups of factors) affecting a single assumption used in the development of Long-Term Scenarios will have an additive effect on that assumption.⁹⁴⁶ We also expect that incorporating a category of factors into the development of Long-Term Scenarios will result in scenarios that differ from scenarios lacking that specific category of factors; that is, the incorporation of a category of factors should have a measurable impact on the Long-Term Scenario, compared to that same Long-Term Scenario, all else equal, if it had not incorporated that category of factors.

414. We believe that the best-available data requirement, which we adopt and discuss further below, should mitigate concerns that transmission providers may undermine Long-Term Regional Transmission Planning by not incorporating categories of factors in a meaningful way.⁹⁴⁷ The best-available data requirement will ensure that the data inputs that transmission providers use to incorporate categories of factors are timely, developed using best practices, and diverse and expert perspectives. We also clarify that, as a consequence of the requirement that all Long-Term Scenarios must be plausible, as well as the requirement that all Long-Term Scenarios must be diverse, both of which we adopt and discuss below, transmission providers must incorporate the categories of factors in the development of Long-Term Scenarios in a way that results in plausible and diverse Long-Term Scenarios.

415. As to the factors within each category that transmission providers must account for when they incorporate each category of factors in the development of Long-Term Scenarios, we require transmission providers to

account for the factors that they have determined are likely to affect Long-Term Transmission Needs. As explained above, these Long-Term Transmission Needs include, but are not limited to, evolving reliability concerns and changes in the resource mix, and changes in demand. For each factor (or group of similar factors) within each category of factors that transmission providers identify, in coordination with stakeholders through an open and transparent process as described below, transmission providers must make a determination as to how that factor (or group of similar factors) is likely to affect Long-Term Transmission Needs. Transmission providers must then account for the factors that they have determined are likely to affect Long-Term Transmission Needs in the development of the Long-Term Scenarios used in Long-Term Regional Transmission Planning. We clarify, however, that transmission providers in a transmission planning region need not account for a factor, stakeholder-identified or otherwise, if they determine that factor is unlikely to affect Long-Term Transmission Needs.

416. We also clarify that a category of factors (*e.g.*, Factor Category Two: Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification) differs from a specific factor (*e.g.*, a specific state law with a decarbonization requirement). We make this distinction because some commenters use only the word “factors” when describing the categories of factors proposed in the NOPR.⁹⁴⁸

417. We disagree with commenters that the categories of factors requirements are too prescriptive,⁹⁴⁹ and we believe that the framework adopted in this final order requiring transmission providers to incorporate categories of factors into the development of Long-Term Scenarios strikes the right balance between prescriptive requirements and flexibility. Transmission providers have discretion to determine whether specific factors must be accounted for within each category (*i.e.*, if the specific factor will likely affect Long-Term Transmission Needs), how to account for specific factors in the development of Long-Term Scenarios (*e.g.*, the method and data used to forecast resource retirements), and how to vary the treatment of each category of factors across Long-Term Scenarios (*e.g.*,

assume all forecasted resource retirements materialize in some but not all Long-Term Scenarios), so long as transmission providers assume that the laws, regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities identified in the first three categories of factors—that transmission providers have determined are likely to affect Long-Term Transmission Needs—are fully met (as discussed below). We believe that each proposed category of factors is broad enough to allow the transmission providers in each transmission planning region to reflect regional differences within the category, as noted by SEIA and NEPOOL.⁹⁵⁰ In response to PG&E’s request that we allow flexibility for transmission providers to use Long-Term Scenarios that best reflect the individual policy and planning environments in their specific transmission planning regions, and to Pattern Energy’s questions about how categories of factors may be modeled,⁹⁵¹ we clarify that transmission providers have the flexibility to develop different Long-Term Scenarios specific to their transmission planning region and develop using assumptions based on the categories of factors.

418. In response to NESCOE, we decline to give transmission providers the flexibility to choose which of the proposed categories of factors to incorporate into Long-Term Scenarios, which NESCOE states would be consistent with the flexibility that the Commission provided to transmission providers in Order No. 1000, where it did “not . . . require the identification of any particular transmission need driven by any particular Public Policy Requirements.”⁹⁵² As noted in The Overall Need for Reform section, there are deficiencies in the Commission’s existing regional transmission planning requirements, including that they fail to ensure that transmission providers adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs. We are concerned that, if transmission providers have flexibility to choose which of the proposed categories of factors to incorporate into the development of Long-Term Scenarios, they will continue to underestimate—or omit entirely—certain known determinants of Long-Term Transmission Needs in their regional

⁹⁴⁵ For example, transmission providers could aggregate the effect of corporate goals by leveraging publicly available surveys of corporations’ clean energy and electrification goals and then using those surveys to inform the assumptions used to develop Long-Term Scenarios (*e.g.*, 10% more clean energy resources and 10% higher load growth for a Long-Term Scenario that assumes full achievement of those goals than in a Long-Term Scenario that does not consider such goals).

⁹⁴⁶ For example, two independent factors that increase the likelihood of future electric storage resource development (*e.g.*, (1) a state law requiring the deployment of at least 5 gigawatts of electric storage resources by 2030 and (2) a Federal investment tax credit for the deployment of electric storage resources) would have a combined effect that exceeds the effect of either factor alone.

⁹⁴⁷ *E.g.*, ACEG Initial Comments at 28.

⁹⁴⁸ *E.g.*, AEE Initial Comments at 9; Evergreen Action Initial Comments at 4.

⁹⁴⁹ ISO-NE Initial Comments at 26; NYISO Initial Comments at 8, 20; PJM Initial Comments at 67.

⁹⁵⁰ NEPOOL Initial Comments at 7; SEIA Reply Comments at 3–4.

⁹⁵¹ Pattern Energy Initial Comments at 24; PG&E Initial Comments at 7.

⁹⁵² NESCOE Initial Comments at 27–28 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 207).

transmission planning processes. Additionally, we note that transmission needs are distinct from categories of factors: as explained above, categories of factors, and specific factors therein, form the basis for assumptions that will be used in the development of Long-Term Scenarios that transmission providers will then use to identify Long-Term Transmission Needs.

419. We also disagree with arguments that we are directing the development of specific transmission facilities.⁹⁵³ As an initial matter, transmission providers retain discretion to determine how specific factors will affect Long-Term Transmission Needs. Moreover, the categories of factors requirements adopted in this final order do not create new transmission needs that did not previously exist, but rather, they improve regional transmission planning processes by requiring transmission providers to identify Long-Term Transmission Needs across a plausible and diverse range of future scenarios and to identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs. If transmission providers do not account in Long-Term Regional Transmission Planning for known determinants of Long-Term Transmission Needs, then those needs would still exist and would likely be resolved, if at all, in a relatively inefficient or less cost-effective manner (*e.g.*, in a piecemeal fashion through local transmission planning processes and/or generator interconnection processes). We are not requiring that transmission providers select any particular Long-Term Regional Transmission Facility and therefore are not directing the development of any particular transmission facilities. Finally, we clarify that while the requirement for transmission providers to incorporate the seven categories of factors adopted in this final order into the development of Long-Term Scenarios is intended to ensure that Long-Term Regional Transmission Facilities are identified for selection to more efficiently or cost-effectively address Long-Term Transmission Needs, we do not believe that concerns over whether a transmission provider appropriately implemented this requirement represent an appropriate basis on which to challenge the cost allocation for one or more individual Long-Term Regional Transmission Facilities. Rather, whether

the allocation of costs is just and reasonable and not unduly discriminatory is governed by the requirement that costs be roughly commensurate with benefits, as discussed in the Regional Transmission Cost Allocation section below.

420. We disagree with Large Public Power's argument that we are ignoring the Commission's fundamental responsibility to facilitate planning to meet the needs of load-serving entities.⁹⁵⁴ As described below, we are requiring all Long-Term Scenarios to be consistent with and fully account for factors in Factor Category Three, which includes state-approved integrated resource plans and the expected supply obligations of load-serving entities. Therefore, transmission providers are required to plan to meet the needs of load-serving entities.

421. We decline to adopt more specific minimum requirements than those described herein for incorporating categories of factors in the development of Long-Term Scenarios, as requested by some commenters.⁹⁵⁵ We believe that the requirements adopted herein, coupled with the other Long-Term Scenarios requirements, including the plausible and diverse and best available data requirements, are sufficiently detailed to address the need for reform without limiting regional flexibility.

b. Specific Categories of Factors

i. NOPR Proposal

422. In the NOPR, the Commission proposed to require transmission providers to incorporate, at a minimum, the following categories of factors in the development of Long-Term Scenarios: (1) Federal, state, and local laws and regulations that affect the future resource mix and demand;⁹⁵⁶ (2) Federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load-serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator

interconnection requests and withdrawals; and (7) utility and corporate commitments and Federal, state, and local goals that affect the future resource mix and demand.⁹⁵⁷

(a) Federal, Federally-Recognized Tribal, State, and Local Laws and Regulations That Affect the Future Resource Mix and Demand (Factor Category One)

(1) Comments

423. Many commenters support the proposed requirement that each Long-Term Scenario incorporate and be consistent with the Federal, state, and local laws and regulations that affect the future resource mix and demand.⁹⁵⁸ AEE, Clean Energy States, and Acadia Center and CLF argue that laws and regulations implementing clean energy and decarbonization policies will be key drivers in changes to the resource mix and demand.⁹⁵⁹ Moreover, AEE notes, 38 states and the District of Columbia have adopted renewable portfolio standards, many of which have been enacted in statute and constitute binding commitments on utilities and retail energy providers.⁹⁶⁰ Clean Energy States similarly assert that the 21 states (plus the District of Columbia and Puerto Rico) with 100% clean energy policies account for 42.3% of United States power sales as of 2020, 49.4% of United States customer accounts, and 51% of United States population.⁹⁶¹ Clean Energy States argue that altogether, these states could see an aggregated demand for 800 TWh of new energy generation to meet their targets.

424. AEE, DC and MD Offices of People's Counsel, and SEIA agree that transmission providers should incorporate the effects of Federal, state, and local laws and regulations on

⁹⁵⁷ *Id.* P. 104.

⁹⁵⁸ Acadia Center and CLF Initial Comments at 8; AEE Initial Comments at 9–10; Breakthrough Energy Initial Comments at 14; California Commission Initial Comments at 17; Clean Energy Associations Initial Comments at 10–11; Clean Energy States Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Exelon Initial Comments at 10–11; New England for Offshore Wind Initial Comments at 2; OMS Initial Comments at 6; Pacific Northwest State Agencies at Initial Comments at 14; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17–18; WE ACT Initial Comments at 4–5.

⁹⁵⁹ Acadia Center and CLF Initial Comments at 8; AEE Initial Comments at 10; Clean Energy States Initial Comments at 3.

⁹⁶⁰ AEE Initial Comments at 10 (citing Energy Info. Admin., *Renewable Energy Explained, Portfolio Standards* (June 29, 2021), <https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php>).

⁹⁶¹ Clean Energy States Initial Comments at 3 (citing Clean Energy States Alliance, *100% Energy Collaborative*, <https://www.cesa.org/projects/100-clean-energy-collaborative/>).

⁹⁵³ *E.g.*, Large Public Power Initial Comments at 20–21; *see also* Alabama Commission Initial Comments at 4; Industrial Customers Initial Comments at 10; Louisiana Commission Initial Comments at 17–19; Pennsylvania Commission Initial Comments at 6.

⁹⁵⁴ Large Public Power Initial Comments at 19–20 (citing 16 U.S.C. 824q, (e)); *see also* NRECA Initial Comments at 17–18 (quoting 16 U.S.C. 824q(b)(4)), 19–20.

⁹⁵⁵ *E.g.*, PIOs Reply Comments at 10.

⁹⁵⁶ NOPR, 179 FERC ¶ 61,028 at P. 104 n.189. The Commission explained that “state or federal laws or regulations” meant “enacted statutes (*i.e.*, passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or municipality, or at the federal level.”

renewable energy development into development of Long-Term Scenarios.⁹⁶² City of New York states that government action that bears the force of law should be reflected in baseline transmission planning studies and not considered as merely one of multiple factors used to develop Long-Term Scenarios.⁹⁶³

425. Southeast PIOs argue that concerns that requiring the incorporation of local laws and regulations in the development of Long-Term Scenarios is unduly burdensome are misplaced at this stage because the details of how it will be done will be established during compliance proceedings.⁹⁶⁴

426. PIOs argue that the Commission should require the same level of engagement with Tribal governments as it does with states and that the Commission should clarify that Long-Term Scenarios must incorporate relevant aspects of Tribal policies.⁹⁶⁵

427. Acadia Center and CLF claim that the Commission should clarify that state laws and regulations that affect the future resource mix and demand include state laws and regulations that affect demand management, such as energy efficiency, distributed generation, flexible load, and demand response because laws and initiatives in this area will also affect transmission needs while providing grid solutions.⁹⁶⁶

428. Center for Biological Diversity states that the Commission must include all Executive Actions, not just laws and regulations, as factors in Long-Term Regional Transmission Planning. Center for Biological Diversity states that allowing transmission providers to decide whether to consider Executive Orders fails to provide stakeholders with the type of clarity that is a goal of the NOPR.⁹⁶⁷

429. As noted above, some commenters oppose the overall categories of factors requirement in this final order and argue that requiring transmission providers to incorporate certain factors, such as laws and regulations that affect the resource mix, will force transmission providers to settle irresolvable conflicts among state policies and conduct transmission

planning that accommodates the policy preferences of some, at the cost of all.⁹⁶⁸

430. Some commenters acknowledge that state laws and regulations may affect the future resource mix and demand but argue against mandatory inclusion such that they cannot discount certain Federal, state, and local laws and regulations.⁹⁶⁹ Idaho Power states that the NOPR proposal does not provide transmission providers with the flexibility necessary to create transmission planning regions that span multiple states and could cause non-jurisdictional entities to opt out of regional transmission planning.⁹⁷⁰ NYISO states that the final order should not require transmission providers to assume across all scenarios the full achievement of all Federal, state, and local laws and regulations that could drive the need for transmission. NYISO also does not think that the final order should require the identification of all Federal, state, and local laws and regulations that may drive the need for transmission over the 20-year transmission planning horizon, but instead should provide each transmission planning region with flexibility.⁹⁷¹

431. Although Duke agrees that many of the categories of factors identified in the NOPR capture a minimum list of factors that are expected to drive changes in the resource mix and demand, it does not support the inclusion of local laws and regulations.⁹⁷²

(2) Commission Determination

432. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category One: Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, in the development of Long-Term Scenarios. We find that the factors in this category have been, and will continue to be, key drivers of Long-Term Transmission Needs and therefore must be accounted for in Long-Term Regional Transmission Planning. Accordingly, we find that failing to account for factors in Factor Category One would hamper the identification, evaluation, and selection of Long-Term Regional Transmission Facilities that

are potentially more efficient or cost-effective solutions to Long-Term Transmission Needs.

433. We clarify that factors in Factor Category One include, among other things, legally binding obligations, incentives (e.g., tax credits), and/or restrictions promulgated by policymakers that will affect new or existing generators, or demand. Further, as discussed in the Additional Categories of Factors section below, we recognize that energy equity and justice laws and regulations are also potential factors within Factor Category One to the extent that they are likely to affect Long-Term Transmission Needs.

434. As discussed in further detail below in the Additional Categories of Factors section, we modify the NOPR proposal for Factor Category One to include federally-recognized Tribal laws and regulations affecting the resource mix and demand because we are persuaded by commenters that contend that such factors have a similar potential to affect Long-Term Transmission Needs as Federal, state, and local laws and regulations. Federally-recognized Tribal laws and regulations mean the legally binding obligations, incentives, and/or restrictions promulgated by federally-recognized Tribes that will affect new or existing generators, or demand. We make similar modifications to Factor Category Two and Factor Category Seven, as discussed in the Factor Category Two and Factor Category Seven sections below.

435. We are not persuaded by Louisiana Commission's argument that requiring transmission providers to incorporate certain factors, such as Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, would result in a transmission buildout that only accommodates the policy preferences of some stakeholders, at the cost of all transmission customers.⁹⁷³ Similarly, we are not persuaded by Undersigned States' contention that policy differences among states may be irresolvable, and therefore the Commission should not require transmission providers to account for laws and regulations in their Long-Term Scenarios.⁹⁷⁴ First, every policy choice—from Federal tax incentives and state regulation of generation, down to local economic development policies—that changes the quantity and location of generation and load contributes to changes in transmission needs. Accordingly, all transmission buildout—whether it occurs through a

⁹⁶² AEE Initial Comments at 17–18, 22; DC and MD Offices of People's Counsel Reply Comments at 5–6; SEIA Initial Comments at 7–8.

⁹⁶³ City of New York Initial Comments at 7.

⁹⁶⁴ Southeast PIOs Reply Comments at 26.

⁹⁶⁵ PIOs Reply Comments at 15.

⁹⁶⁶ Acadia Center and CLF Initial Comments at 9.

⁹⁶⁷ Center for Biological Diversity Initial Comments at 3, 9–12.

⁹⁶⁸ Louisiana Commission Initial Comments at 17–18; Undersigned States Initial Comments at 3.

⁹⁶⁹ Ameren Initial Comments at 9–10; NESCOE Initial Comments at 27–28; NYISO Initial Comments at 8, 20.

⁹⁷⁰ Idaho Power Initial Comments at 7.

⁹⁷¹ NYISO Initial Comments at 8.

⁹⁷² Duke Initial Comments at 13–14.

⁹⁷³ Louisiana Commission Initial Comments at 17.

⁹⁷⁴ Undersigned States Initial Comments at 3.

local or regional transmission plan, or through a near-term transmission planning process or a more forward-looking one—is a reflection, at least in part, of Federal, federally-recognized Tribal, state, and local laws and regulations that drive transmission needs. Rather than a unique feature of Long-Term Regional Transmission Planning, transmission planning of any kind will inherently reflect the policy choices of multiple decisionmakers, because the quantity and location of generation and load are shaped by multiple decisionmakers.

436. Second, we find that requiring transmission providers to properly account for known determinants of Long-Term Transmission Needs is necessary to ensure just and reasonable rates. Specifically, because, as described above, Long-Term Transmission Needs driven by disparate policy decisions would continue to exist, regardless of whether they were identified in Long-Term Regional Transmission Planning, failing to identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs will result in unjust and unreasonable rates. We note that some policy decisions are reflected in laws and regulations, which can affect load-serving entities' supply obligations, and in transmission planning regions with vertically integrated utilities, some policy decisions are reflected in the integrated resource plans approved by retail regulators.

437. We are not endorsing the merits of any specific Federal, federally-recognized Tribal, state, or local laws and regulations or of any specific state-approved integrated resource plans. We emphasize that the Commission's policies are technology neutral, and we are not establishing a preference for certain types of generation or energy end uses. We acknowledge that, in some instances, a policy choice in one jurisdiction may reduce or negate the effect of a policy choice in another jurisdiction. However, the fact that certain factors may have conflicting effects on Long-Term Transmission Needs is not a basis to conclude that the effects of laws and regulations or state-approved integrated resource plans should be ignored or discounted.

(b) Federal, Federally-Recognized Tribal, State, and Local Laws and Regulations on Decarbonization and Electrification (Factor Category Two)

(1) Comments

438. Several commenters support the proposed requirement that Long-Term Scenarios incorporate Federal, state, and

local laws and regulations on decarbonization and electrification.⁹⁷⁵ Illinois Commission notes that, in Illinois, the Climate and Equitable Jobs Act of 2021 will affect future demand and the supply mix and that Long-Term Regional Transmission Planning will be critical to meeting Illinois' policy goals.⁹⁷⁶ New England for Offshore Wind states that electrification to meet New England states' greenhouse gas emissions mandates will dramatically increase electricity load and require massive amounts of clean energy.⁹⁷⁷ Pattern Energy states that Federal and state legislative efforts to promote decarbonization should be the basis of scenario modeling for generation and demand.⁹⁷⁸ Center for Biological Diversity states that the Commission should identify decarbonization as an objective in Long-Term Regional Transmission Planning because it has the authority and responsibility to prioritize decarbonization in the transmission planning process since these policies bear directly on the provision of transmission service.⁹⁷⁹

439. Nevada Commission acknowledges that other state policies and its own integrated resource planning process should be considered in Long-Term Regional Transmission Planning even though it does not support other state policies affecting Nevada ratepayers.⁹⁸⁰ Utah Division of Public Utilities states that the impact of state policies should be part of the Long-Term Regional Transmission Planning scenario analysis.⁹⁸¹ Cypress Creek asserts that the Commission should include state policy requirements in a uniform set of assumptions that are applicable across all Long-Term Scenarios.⁹⁸²

(2) Commission Determination

440. We adopt the NOPR proposal, with modification, to require

⁹⁷⁵ Acadia and CLF Initial Comments at 9; Center for Biological Diversity Initial Comments at 7–9; Clean Energy Associations Initial Comments at 10–11; DC and MD Offices of People's Counsel Reply Comments at 6; Illinois Commission Initial Comments at 4–5; New England for Offshore Wind Initial Comments at 2–3; Pacific Northwest State Agencies at Initial Comments at 14; Pattern Energy Initial Comments at 26; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17–18; Renewable Northwest Initial Comments at 19–22.

⁹⁷⁶ Illinois Commission Initial Comments at 4–5.

⁹⁷⁷ New England for Offshore Wind Initial Comments at 2–3.

⁹⁷⁸ Pattern Energy Initial Comments at 26.

⁹⁷⁹ Center for Biological Diversity Initial Comments at 7–9 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 89–93).

⁹⁸⁰ Nevada Commission Initial Comments at 8.

⁹⁸¹ Utah Division of Public Utilities Reply Comments at 4.

⁹⁸² Cypress Creek Reply Comments at 5–6.

transmission providers in each transmission planning region to incorporate Factor Category Two: Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification, in the development of Long-Term Scenarios. Similar to Factor Category One, we find that the factors in this category have been, and will continue to be, key drivers of Long-Term Transmission Needs and therefore must be accounted for in Long-Term Regional Transmission Planning. We clarify that this category of factors includes legally binding obligations, incentives, and/or restrictions that affect Long-Term Transmission Needs in different ways than Factor Category One, for example, by limiting the carbon intensity of electricity generation or electrifying energy end uses and thereby significantly increasing electricity use in certain sectors of the economy, such as transportation and building heating and cooling. We acknowledge that there could be overlap between Factor Categories One and Two because a certain law or regulation could reasonably be considered to fit into both categories. In such a circumstance, transmission providers must account for the law or regulation in one of the two categories, not both, to avoid double-counting of that factor's anticipated effect on Long-Term Transmission Needs. Since transmission providers must account for and be consistent with, and not discount, factors in the first three categories of factors equally once the transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs, we do not believe it is necessary to ensure that a certain factor is considered as part of Factor Category One instead of Factor Category Two (or vice versa), but rather it is only necessary to ensure that these factors are accounted for in the development of Long-Term Scenarios.

441. In addition, based on the record before us, we modify the NOPR proposal for Factor Category Two to include federally-recognized Tribal laws and regulations on decarbonization and electrification because we are persuaded by commenters that argue that such factors have the same potential to affect Long-Term Transmission Needs as Federal, state, and local laws and regulations on decarbonization and electrification.

442. Similar to our response in the Factor Category One section to commenters arguing that categories of factors involving Federal, federally-recognized Tribal, state, and local laws and regulations would provide

preference to some at the cost of all or result in irresolvable conflict,⁹⁸³ we find that differences in if and how government entities promulgate laws and regulations concerning decarbonization and electrification (*i.e.*, factors in Factor Category Two) do not diminish the effect of such laws and regulations. As such, Long-Term Scenarios must account for these key drivers of Long-Term Transmission Needs so that transmission providers can identify such needs through Long-Term Regional Transmission Planning and can identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs.

(c) State-Approved Utility Integrated Resource Plans and Expected Supply Obligations for Load-Serving Entities (Factor Category Three)

(1) Comments

443. Several commenters support the proposed requirement that each Long-Term Scenario incorporate state-approved integrated resource plans and expected supply obligations for load-serving entities.⁹⁸⁴ NRECA and TAPS state that using Long-Term Scenarios that satisfy expected load-serving entity supply obligations is consistent with FPA section 217(b)(4)'s directive to facilitate the planning and expansion of transmission to meet the reasonable needs of load-serving entities to satisfy their service obligations.⁹⁸⁵ NRECA asserts that this category should be moved to the top of the list of categories of factors because state-approved integrated resource plans and load-serving entity supply obligations will incorporate state laws and regulations affecting resource mix, demand, decarbonization, and electrification. Additionally, NRECA contends that the changing characteristics of the distribution grid, such as distributed energy resources, storage, demand response, energy efficiency, and electrification of demand, will affect load-serving entity needs and should be incorporated in this category of factors.⁹⁸⁶ Clean Energy Associations and ACEG agree.⁹⁸⁷

444. APPA and ACEG argue that the final order should focus on the resource plans of load-serving entities and include a requirement for transmission providers to include in their Long-Term Regional Transmission Planning process a requirement to coordinate with load-serving entities.⁹⁸⁸ ACEG argues that such a requirement is necessary because not all load-serving entities either own generation or are overseen by a state regulator, meaning that they must rely on the Commission to ensure that transmission planning meets their needs.⁹⁸⁹

445. Several commenters clarify that they support the inclusion of load-serving entity demand as a factor in Long-Term Scenarios.⁹⁹⁰ In addition, some commenters support the inclusion of load-serving entity generation resource planning as a factor in Long-Term Scenarios.⁹⁹¹ PIOs argue that the Commission should require load-serving entities to provide their generation and demand forecasts to transmission planning entities.⁹⁹² ACEG agrees and argues that PIOs' recommendation will decrease the burden on transmission planning entities and provide them with the information they need to determine the future resource mix.⁹⁹³

446. Entergy asserts that the Commission has identified the appropriate factors but explains that not all states conduct commission proceedings related to integrated resource plans and, for those states that do, the timelines are not necessarily the same. Thus, Entergy requests that the Commission clarify that the term "state-approved utility integrated resource plans" will be construed broadly to include any resource plan developed and reviewed through a retail commission proceeding and submitted to the relevant transmission provider for use in Long-Term Regional Transmission Planning. Entergy asserts that such clarification would result in a range of benefits such as consistency of data with current local, state, and Federal laws and expected retirements, additions, and corporate goals.⁹⁹⁴

(2) Commission Determination

447. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Three: state-approved integrated resource plans and expected supply obligations for load-serving entities, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Three because it reflects the outcomes of retail-level regulatory proceedings that will affect Long-Term Transmission Needs. Further, incorporation of Factor Category Three into Long-Term Scenarios will ensure that transmission providers properly account for resource planning and anticipated changes to demand, including increased integration of distributed energy resources. We note that the Commission shares concurrent jurisdiction over the bulk power system with retail regulators,⁹⁹⁵ and we agree with commenters that note that FPA section 217(b)(4) directs the Commission to facilitate the planning and expansion of transmission to meet the reasonable needs of load-serving entities to satisfy their service obligations.⁹⁹⁶

448. In response to commenters that note some retail regulators may review but not formally approve integrated resource plans, we clarify that, for this category of factors, state-approved integrated resource plans includes resource plans that are developed and reviewed through a retail proceeding in jurisdictions where the retail regulator does not formally approve such plans.⁹⁹⁷ We grant Entergy's clarification request that the term "state-approved utility integrated resource plans" be construed broadly to include any resource plan developed and reviewed through a retail commission proceeding and submitted to the relevant transmission provider for use in Long-Term Regional Transmission Planning because it would enable a more complete consideration of state-approved integrated resource plans and

⁹⁸³ Louisiana Commission Initial Comments at 17–19; Undersigned States Initial Comments at 3. Comments originally summarized in PP 404–405.

⁹⁸⁴ California Commission Initial Comments at 17; NRECA Initial Comments at 30; Pine Gate Initial Comments at 23; PIOs Initial Comments at 17–18; US Chamber of Commerce Initial Comments at 6–7.

⁹⁸⁵ NRECA Initial Comments at 30–31; TAPS Initial Comments at 2, 7–8 (citing NOPR, 179 FERC ¶ 61,028 at P 106); *see also* APPA Initial Comments at 28.

⁹⁸⁶ NRECA Initial Comments at 30–31 n.85.

⁹⁸⁷ ACEG Reply Comments at 22; Clean Energy Associations Reply Comments at 6–7.

⁹⁸⁸ ACEG Reply Comments at 22; APPA Initial Comments at 27–28.

⁹⁸⁹ ACEG Reply Comments at 22–23.

⁹⁹⁰ ACEG Reply Comments at 22–23; Clean Energy Associations Reply Comments at 7; DC and MD Offices of People's Counsel Reply Comments at 4; PIOs Initial Comments at 18; PIOs Reply Comments at 10.

⁹⁹¹ ACEG Reply Comments at 22–23; Clean Energy Associations Reply Comments at 7; DC and MD Offices of People's Counsel Reply Comments at 4.

⁹⁹² PIOs Initial Comments at 19.

⁹⁹³ ACEG Reply Comments at 23.

⁹⁹⁴ Entergy Initial Comments at 15–16.

⁹⁹⁵ Compare 16 U.S.C. 824d(a) (providing the Commission authority to regulate the rates charged by public utilities in connection with the transmission or wholesale sale of electric energy), with *id.* 824(a) (reserving certain state authorities).

⁹⁹⁶ 16 U.S.C. 824q(b)(4) ("The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.").

⁹⁹⁷ Entergy Initial Comments at 15–16.

expected supply obligations for load-serving entities.

449. In response to APPA and ACEG's request for the Commission to require transmission providers to coordinate with load-serving entities,⁹⁹⁸ we note that we require transmission providers, as described in further detail below, to provide an open and transparent process in their OATT that provides stakeholders, including load-serving entities, with a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios.⁹⁹⁹ However, in response to PIOs' request that the Commission require load-serving entities to provide their generation and demand forecast to transmission providers, we agree that such information will assist transmission providers in developing Long-Term Scenarios. Therefore, consistent with the information exchange transmission planning principle established in Order No. 890,¹⁰⁰⁰ we require load-serving entities that are taking transmission service pursuant to an OATT to provide transmission providers with information on the load-serving entities' projected loads and resources over the planning horizon.

(d) Trends in Technology and Fuel Costs Within and Outside of the Electricity Supply Industry, Including Shifts Toward Electrification of Buildings and Transportation (Factor Category Four)

(1) Comments

450. Several commenters emphasize the importance of incorporating assumptions regarding shifts towards electrification in Long-Term Scenarios.¹⁰⁰¹ Clean Energy Buyers

⁹⁹⁸ ACEG Reply Comments at 22; APPA Initial Comments at 27–28.

⁹⁹⁹ See *infra* Stakeholder Process and Transparency section.

¹⁰⁰⁰ The information exchange transmission planning principle requires network transmission customers to submit information on their projected loads and resources on a comparable basis (*e.g.*, planning horizon and format) as used by transmission providers in planning for their native load. Point-to-point transmission customers are required to submit their projections for need of service over the planning horizon and at what receipt and delivery points. To the extent applicable, transmission customers should also provide information on existing and planned demand resources and their impact on demand and peak demand. Transmission providers, in consultation with their customers and other stakeholders, must develop guidelines and a schedule for the submittal of such customer information. Order No. 890, 118 FERC ¶ 61,119 at PP 486–487.

¹⁰⁰¹ Clean Energy Associations Initial Comments at 11; Clean Energy Buyers Initial Comments at 15–16; DC and MD Offices of People's Counsel Initial

assert that regional flexibility should not be used to diminish the representation in Long-Term Scenarios of significant load growth from the commercial and industrial sectors and electrification of transportation.¹⁰⁰² Likewise, DC and MD Offices of People's Counsel assert that regional flexibility should be reflected in the actual inputs for these factors, rather than their inclusion in or exclusion from Long-Term Scenarios, noting, for example, that electrification forecasts in some areas are increasing load growth estimates by 30%.¹⁰⁰³ Clean Energy Associations argue that, to keep pace with changes in supply and demand, Long-Term Scenarios should incorporate aging infrastructure and planned replacements, along with load and generation trends informed by both historical data and applicable policy drivers.¹⁰⁰⁴

451. Other commenters emphasize the trends in specific technology costs, such as long-duration storage. ENGIE states that advances in longer-duration storage and advancing photovoltaic technologies may affect the ability to develop resources in areas previously considered to be uneconomic, which could affect the resource and demand mix.¹⁰⁰⁵ Form Energy argues that the inclusion of diverse, long-duration electric storage technologies would require significantly fewer new transmission needs.¹⁰⁰⁶

452. Pine Gate supports the inclusion of trends in technology and fuel costs in Long-Term Scenarios; however, Pine Gate requests that the Commission clarify what type of data would constitute a “trend” and how it expects transmission providers to assure that trend-related input is objective and representative of the “best available data.”¹⁰⁰⁷ Similarly, US DOE recommends that the Commission clarify whether the term “trends in technology and fuel costs” refers to trends in fuel cost and trends in technology, or rather trends in the cost of fuel and trends in the cost of technology. If the Commission is referring to the former, US DOE recommends that the Commission consider the phrase “trends in fuel costs and in the cost, performance, and availability of generation, storage, and

Comments at 11–12; ENGIE Initial Comments at 3; PJM Market Monitor Initial Comments at 3.

¹⁰⁰² Clean Energy Buyers Initial Comments at 15–16.

¹⁰⁰³ DC and MD Offices of People's Counsel Initial Comments at 11–12.

¹⁰⁰⁴ Clean Energy Associations Initial Comments at 12.

¹⁰⁰⁵ ENGIE Initial Comments at 3.

¹⁰⁰⁶ Form Energy Initial Comments at 2–3.

¹⁰⁰⁷ Pine Gate Initial Comments at 24.

transmission technologies.” US DOE further recommends that the Commission provide a non-exhaustive list of examples of cost and technology trends that transmission planners could consider.¹⁰⁰⁸

453. SEIA recommends that the Commission direct transmission providers to use the data and models used in NREL's Electrification Futures Study, Solar Futures Study, Storage Futures Study, and Transportation Futures Study.¹⁰⁰⁹ PIOs disagree with granting discretion to transmission providers to define trends in technology and fuel costs because PIOs state that it could empower them to distort the modeling process and create Long-Term Scenarios that are meaningless.¹⁰¹⁰

454. PIOs argue that the Commission should require transmission providers to use certain values for trends in technology and fuel costs within and outside of the electricity supply industry.¹⁰¹¹

455. New York TOs argue that trends in technology costs are amorphous and therefore should not be prescribed as a required factor for transmission providers to consider.¹⁰¹² Similarly, PPL criticizes the Commission's proposed requirement that transmission providers forecast trends in technology without providing concrete assumptions to use, or without a guarantee for cost recovery for investments that are based on those uncertain forecasts.¹⁰¹³

(2) Commission Determination

456. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Four: trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Four into the development of Long-Term Scenarios because the relative cost of constructing and operating different types of generation or storage resources and the relative cost of electrifying certain energy end uses will affect Long-Term Transmission Needs. We further find that this requirement is necessary to ensure that transmission providers

¹⁰⁰⁸ US DOE Initial Comments at 12–13.

¹⁰⁰⁹ SEIA Initial Comments at 10.

¹⁰¹⁰ PIOs Initial Comments at 19.

¹⁰¹¹ *Id.* at 17–19.

¹⁰¹² New York TOs Initial Comments at 11–12.

¹⁰¹³ PPL Initial Comments at 8.

develop plausible Long-Term Scenarios that account for technological changes expected over the transmission planning horizon, facilitating transmission providers' identification of Long-Term Transmission Needs.

457. As requested by commenters, including US DOE, we modify this category of factors in the final order to clarify that this category of factors is meant to capture changes in the cost, as well as the performance and availability, of certain technologies relevant to the electric industry.¹⁰¹⁴ In response to commenters arguing that trends in technology costs are amorphous and should not be included in the final order as a required category of factors, we disagree. However, as discussed above, we grant transmission providers discretion to determine whether specific trends identified in Factor Category Four are likely to affect Long-Term Transmission Needs and how to account for those specific trends in Long-Term Scenarios.¹⁰¹⁵ As discussed in further detail below, transmission providers also have some discretion to discount or place more weight on the anticipated effects on Long-Term Transmission Needs due to factors in this category.

458. In response to comments from US DOE,¹⁰¹⁶ we clarify that trends in fuel costs and in the cost, performance, and availability of generation, storage, and building and transportation electrification technologies may include, but are not limited to, cost and technology trends for: utility-scale generation construction costs for different generating technologies; distributed energy resources; storage technologies with differing duration limitations; carbon capture and sequestration; small modular nuclear; light-, medium-, and heavy-duty electric vehicles and electric vehicle supply equipment; and ground- and air-source heat pumps. While we agree with US DOE that transmission providers should consider trends in the cost, performance, and availability of transmission technologies as part of their evaluation of potential solutions to Long-Term Transmission Needs, we do not believe that these trends should be included as factors in this category because trends in the cost, performance, and availability of transmission technologies do not drive Long-Term Transmission Needs. We also agree with commenters that note that the effects of

the factors in this category may vary significantly, such as shifts towards electrification leading to significant load growth, or cost reductions for emerging technologies, like long-duration electric storage resources, mitigating some new transmission needs.

(e) Resource Retirements (Factor Category Five)

(1) Comments

459. Several commenters support the proposed requirement that each Long-Term Scenario incorporate resource retirements as a category of factors.¹⁰¹⁷ PJM Market Monitor states that PJM faces the potential for the retirement of large coal resources and that the PJM capacity market design and the transmission planning process need to identify these specific resources well in advance and ensure an efficient response to obviate the need for nonmarket cost-of-service contracts to retain generation while transmission is constructed.¹⁰¹⁸

460. PIOs and NYISO both argue that the Commission should further specify that transmission providers must incorporate expected trends in resource retirements rather than just announced retirements into Long-Term Scenarios.¹⁰¹⁹ PIOs state the Commission should require transmission providers to (1) specify how they will use generator age and condition data to predict retirements, (2) include announced retirements, and (3) specify how they will reflect trends and incentives for distributed energy resources, as well as how they will quantify these trends.¹⁰²⁰

461. NYISO states that the final order should confirm that each transmission planning region has the authority and flexibility to account for likely resource retirements that have not been announced by the resource based on factors that include the facility's age, its emission profile, applicable laws and regulations, and other factors.¹⁰²¹ Similarly, Pine Gate asserts that

resource retirements should be included at the earliest opportunity as there is often a significant gap of time between when a public announcement is made and when the official notice of deactivation is communicated to the transmission provider.¹⁰²²

462. SEIA states that transmission providers should only be required to include the retirement of resources that have provided notice of pending retirement pursuant to the applicable tariff provisions.¹⁰²³ PJM supports engaging in transparent economic impact analyses of generation resource retirements but asserts that such analyses might disclose confidential information about specific generators. Therefore, PJM contends that the Commission will need to provide clear direction on how it wishes to address these issues, especially since masking of data is not a practical solution once the transmission case is released.¹⁰²⁴

(2) Commission Determination

463. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Five: resource retirements, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Five because resource retirements expected over the transmission planning horizon will affect Long-Term Transmission Needs. Commenters generally support requiring this category of factors, but commenters disagree as to how transmission providers should account for projected resource retirements that have not been publicly announced.¹⁰²⁵

464. In response to those commenters, we clarify that, to develop plausible Long-Term Scenarios, transmission providers must, in incorporating Factor Category Five into the development of Long-Term Scenarios, account for likely resource retirements beyond those that have been publicly announced. The record indicates that resource retirements have significantly influenced the supply of electricity in the past and are expected to do so in the coming decades.¹⁰²⁶ The North

¹⁰¹⁴ Pine Gate Initial Comments at 24; US DOE Initial Comments at 12.

¹⁰¹⁵ See New York TOs Initial Comments at 11–12; PPL Initial Comments at 8.

¹⁰¹⁶ US DOE Initial Comments at 12–13.

¹⁰¹⁷ Breakthrough Energy Initial Comments at 14; NRECA Initial Comments at 31; NYISO Initial Comments at 24; PIOs Initial Comments at 21; SPP Market Monitor Initial Comments at 9; *see also* PJM Market Monitor at 3 (“PJM faces the potential retirement . . . of a significant amount of coal resources in the next five years. Both the PJM capacity market and design and the transmission planning process need to identify these specific resources well in advance and plan for their retirement in order to ensure an efficient response and to obviate the need for nonmarket cost of service contracts to retain the generation while transmission is constructed.”).

¹⁰¹⁸ PJM Market Monitor Initial Comments at 3.

¹⁰¹⁹ NYISO Initial Comments at 24; PIOs Initial Comments at 21.

¹⁰²⁰ PIOs Initial Comments at 21.

¹⁰²¹ NYISO Initial Comments at 24.

¹⁰²² Pine Gate Initial Comments at 24.

¹⁰²³ SEIA Initial Comments at 10.

¹⁰²⁴ PJM Initial Comments at 6, 69.

¹⁰²⁵ NYISO Initial Comments at 24; Pine Gate Initial Comments at 24; PIOs Initial Comments at 21.

¹⁰²⁶ *See supra* note 241; Colorado Consumer Advocate Initial Comments, attach. 7 (US DOE, *Staff Report to the Secretary on Electricity Markets and Reliability* (Aug. 2017)) at 13–14 (stating that 132 GW of generation capacity retired between 2002 and 2016—approximately 15% of the installed capacity in 2002—due to the advantaged economics

American Electric Reliability Corporation's 2021 Long-Term Reliability Assessment reports nearly 50 GW of confirmed thermal generation resource retirements by 2026 and acknowledges that many more are yet to be announced.¹⁰²⁷ In addition, the record reflects that publicly announced resource retirements are only a fraction of the resource retirements expected over the required 20-year transmission planning horizon.¹⁰²⁸ Given the significance of resource retirements, and the limited scope of publicly announced resource retirements, we find that transmission providers must account for expected retirements that have not been publicly announced to meet this final order's requirement that transmission providers develop a plausible set of Long-Term Scenarios.¹⁰²⁹

465. We provide flexibility to transmission providers to propose on compliance with this final order how to account for resource retirements that might take place over the transmission planning horizon, in addition to those that have been publicly announced. We note, for example, that transmission providers could propose to account for expected retirements by considering factors such as a generating facility's age, its emissions profile, its projected costs and revenues, and any applicable laws and regulations that may affect a generating facility's continued operation over the transmission planning horizon.¹⁰³⁰ To the extent that certain

of natural gas-fired generation, low electricity demand growth, the deployment of variable energy resources, and regulatory requirements); *see also*, e.g., AEP Initial Comments at 4 n.12.

¹⁰²⁷ SEIA Initial Comments at 9 (citing North American Electric Reliability Corporation, *2021 Long-Term Reliability Assessment*, at 30, 35 (Dec. 2021)). The North American Electric Reliability Corporation states that long-range retirement projects based on confirmed retirements could be "significantly understated" because generator retirement announcements can be made as late as 90 days prior to planned deactivation in some areas. The North American Electric Reliability Corporation's 2021 reported retirements through 2026 increased 126% compared to the North American Electric Reliability Corporation's 2020 estimates; and the North American Electric Reliability Corporation's 2022 reported retirements through 2026 increased compared to the North American Electric Reliability Corporation's 2021 retirements. *See* North American Electric Reliability Corporation, *2021 Long-Term Reliability Assessment*, at 35 (Dec. 2021); NERC, *2022 Long-Term Reliability Assessment*, at 17 (Dec. 2022).

¹⁰²⁸ For example, announced retirements account for less than half of MISO's projected retirements over a 20-year transmission planning horizon. *See* MISO Initial Comments at 35 (citing MISO, *MISO Futures Report*, at 14–19, (Dec. 2021), <https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf>).

¹⁰²⁹ *See infra* Types of Long-Term Scenarios section.

¹⁰³⁰ For example, MISO assumes age-based resource retirements which vary by resource type

laws and regulations identified by stakeholders in Factor Categories One and Two will necessitate the retirement of certain resources, we reiterate that transmission providers must develop Long-Term Scenarios that are consistent with such laws and regulations.

466. In response to PJM's concerns that conducting transparent economic impact analyses of generation resource retirements could lead to the disclosure of confidential information about specific generators, we note that the Commission has previously acknowledged that tension exists between ensuring transparency in transmission planning processes and protecting confidential information, including commercially sensitive information.¹⁰³¹ We note that we are not specifying how transmission providers must estimate resource retirements, and we clarify that transmission providers may include what they believe to be appropriate confidentiality protections in their proposals to account for resource retirements that might take place over the transmission planning horizon. The Commission will evaluate those proposals by using the established principles in Order No. 890,¹⁰³² as well as precedent on existing confidentiality protections with respect to transmission planning that the Commission has previously found comply with the Order No. 890 principles, to guide its findings on whether such protections are appropriate.

(f) Generator Interconnection Requests and Withdrawals (Factor Category Six)

(1) Comments

467. Several commenters support the proposed requirement that each Long-Term Scenario incorporate generator interconnection requests and withdrawals.¹⁰³³ Pattern Energy argues that generation interconnection queues are indicative of the market for generation capacity additions and should also be a major source for generation assumptions in both near-term and long-term scenario

and scenario, over a 20-year transmission planning horizon. In a 2021 study, MISO assumes coal-fired resources will retire at age 46 in one scenario, and age 36 in another. MISO assumes utility-scale solar resources will retire at age 25 in every scenario. MISO also incorporates resource retirements announced by the resource owner, stated in an integrated resource plan, or filed in MISO's Attachment Y. *See* MISO Initial Comments at 35 (citing MISO, *MISO Futures Report*, at 14–19, (Dec. 2021), <https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf>).

¹⁰³¹ *Sw. Power Pool, Inc.*, 137 FERC ¶ 61,227, at P 20 (2011).

¹⁰³² Order No. 890, 118 FERC ¶ 61,119 at PP 471–476.

¹⁰³³ Breakthrough Energy Initial Comments at 14; Cypress Creek Reply Comments at 5–7.

planning.¹⁰³⁴ SEIA supports the proposed requirement with the caveat that transmission providers should only include interconnection customers that have signed a facilities study agreement, or other applicable study agreement.¹⁰³⁵ Cypress Creek asserts that the Commission should require transmission providers to include the proposed generator interconnection requests in the queue that have completed a system impact study as part of a uniform set of assumptions applicable across all scenarios.¹⁰³⁶

468. CAISO and MISO state that their regional transmission planning processes already include projects in the generator interconnection queue.¹⁰³⁷ MISO further explains that it considers the generator interconnection queue when determining the location where future generation will interconnect, but MISO also states that transmission providers and their stakeholders need to have flexibility, including how to consider trends in interconnection queue requests.¹⁰³⁸ Further, MISO argues that "generation interconnection requests and withdrawals" as stated in the NOPR is unclear regarding how the transmission provider must weigh withdrawals differently than requests. Therefore, MISO requests that the Commission revise the NOPR proposal to require transmission providers to "consider activity in the generation interconnection queue."¹⁰³⁹

469. Nebraska Commission asserts that the Commission should not include interconnection request withdrawals as a factor because it does not follow the Commission's cost causation principles and would incentivize additional interconnection requests. For example, Nebraska Commission states, most interconnection requests in SPP are duplicative, and entities compare costs among their requests once they are analyzed. Nebraska Commission asserts that such requests could be used to game the transmission planning process, create additional backlogs in the interconnection queue, and shift costs from interconnection customers to transmission customers.¹⁰⁴⁰

470. Likewise, Omaha Public Power claims that, until generator interconnection reform is enacted, the use of interconnection queues and withdrawals as factors will lead to

¹⁰³⁴ Pattern Energy Initial Comments at 26.

¹⁰³⁵ SEIA Initial Comments at 10.

¹⁰³⁶ Cypress Creek Reply Comments at 5–7.

¹⁰³⁷ CAISO Initial Comments at 34; MISO Initial Comments at 35.

¹⁰³⁸ MISO Initial Comments at 35–36.

¹⁰³⁹ *Id.* at 36.

¹⁰⁴⁰ Nebraska Commission Initial Comments at 4–5.

scenario inaccuracy due to the size of interconnection backlogs and speculative nature of many queued projects.¹⁰⁴¹ Dominion also opposes using the number and size of interconnection requests as a basis for transmission planning because speculative interconnection requests could stimulate transmission development in areas slated for development by private interests.¹⁰⁴²

471. PJM Market Monitor states that, while there are many comments on the significant renewable resources PJM will connect to its grid, based on historic completion rates and effective load carry capability derate factors, only 5.6% of renewable resources are expected to go into service.¹⁰⁴³

(2) Commission Determination

472. We adopt the NOPR proposal to require transmission providers in each transmission planning region to incorporate Factor Category Six: generator interconnection requests and withdrawals, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Six because generation interconnection queues provide important information about future generation development over the transmission planning horizon and therefore affect Long-Term Transmission Needs. Multiple RTOs/ISOs explain that their regional transmission planning processes already account for generation projects in the interconnection queue, but MISO notes that transmission providers need flexibility in how to incorporate that data into the development of Long-Term Scenarios.¹⁰⁴⁴ In response to MISO's concerns, we reiterate that transmission providers have discretion to determine how to account for all factors, including interconnection requests and withdrawals, in Long-Term Scenarios.

473. We disagree with commenters that argue that, because many interconnection requests are speculative and/or duplicative, requiring transmission providers to incorporate Factor Category Six into the development of Long-Term Scenarios will compromise the accuracy of Long-Term Scenarios, shift costs to transmission customers that should be borne by interconnection customers, or create an incentive for additional interconnection requests that could slow down interconnection queue

processing.¹⁰⁴⁵ We note that over the years, and recently with Order No. 2023, transmission providers and the Commission have adopted changes to generator interconnection procedures to reduce the submission of speculative interconnection requests in the interconnection queue. For example, interconnection requests require significant financial commitments from the interconnection customer (e.g., application fees, study deposits, and site control requirements), which the Commission made more stringent in Order No. 2023.¹⁰⁴⁶ Noting that, as discussed above, transmission providers will have discretion as to how they account for factors in Long-Term Scenarios and may determine whether certain generator interconnection requests are speculative and/or duplicative, such that the requests are unlikely to affect Long-Term Transmission Needs, and then make corresponding adjustments to their Long-Term Scenarios. As discussed in further detail below, transmission providers can also account for uncertainty by discounting or putting more weight on the anticipated effects on Long-Term Transmission Needs due to factors in this category. Additionally, we believe that the existence of a large number of interconnection requests in a certain area, even if some of those requests are speculative, indicates that generation developers have an interest in interconnecting resources in that area, which Long-Term Scenarios should take into account.

(g) Utility and Corporate Commitments and Federal, Federally-Recognized Tribal, State, and Local Policy Goals That Affect Long-Term Transmission Needs (Factor Category Seven)

(1) Comments

474. Some commenters generally support the proposed requirement to incorporate in Long-Term Scenarios utility and corporate commitments and Federal, state, and local goals that affect the future resource mix and demand.¹⁰⁴⁷ ACEG contends that FPA

section 217(b)(4) supports the Commission's proposed requirement to include public policies and utility and corporate renewable procurement goals within Long-Term Scenarios because load-serving entities' service obligations will depend upon both public policies and the resource preferences of their customers.¹⁰⁴⁸ AEE highlights the role of local goals by noting that 29 of the 50 most populous cities in the United States have set clean or renewable energy targets.¹⁰⁴⁹

475. Advanced Energy Buyers argue that private efforts to use more low- and zero-carbon electricity are significantly affecting the resource mix and in turn transmission needs, noting that since 2014, commercial and industrial customers have contracted for more than 52 GW of clean energy in the United States, with annual increases every year since 2016.¹⁰⁵⁰ Moreover, Advanced Energy Buyers state, corporate and industrial customer demand for renewable energy in the United States is expected to reach about 85 GW by 2030.¹⁰⁵¹ Advanced Energy Buyers state that, in some markets, corporate demand is already a dominant driver of renewable energy deployment, as in Illinois, where corporate procurement accounted for roughly one-third of total renewable deployment.¹⁰⁵² SEIA states that, for corporate commitments, transmission providers should include data from the Clean Energy Buyers Association Deal Tracker, and for utility commitments, transmission providers should include

driven by consumer, utility, and corporate preferences, state public policies, and the cost competitiveness of renewable energy. The Commission's transmission planning and cost allocation standards must be up to the challenge of enabling this transition while ensuring the continued provision of reliable and affordable electricity at just and reasonable rates.").

¹⁰⁴⁸ ACEG Initial Comments at 26–29.

¹⁰⁴⁹ AEE Initial Comments at 10–11 (citing Third Way, *Utilities, Cities, and States with Clean Energy Targets* (July 30, 2021), <https://www.thirdway.org/graphic/utilities-cities-and-states-with-clean-energy-targets>).

¹⁰⁵⁰ Advanced Energy Buyers Initial Comments at 5 (citing Clean Energy Buyers Alliance, *State of the Market 2022*, <https://cebayers.org/state-of-the-market/>).

¹⁰⁵¹ *Id.* at 5–6 (citing Wood Mackenzie, *Corporates Usher in New Wave of US Wind and Solar Growth* (Aug. 2019), <https://www.woodmac.com/our-expertise/focus/Power--Renewables/corporates-usher-in-new-wave-of-u.s.-wind-and-solar-growth/>).

¹⁰⁵² *Id.* at 6 (citing Advanced Energy Economy, *Adding it All Up for Voluntary Buyers of Renewable Energy* (Jan. 2021), <https://blog.advancedenergyunited.org/adding-it-all-up-for-voluntary-buyers-of-renewable-energy>; Microsoft, *Greener datacenters for a brighter future: Microsoft's commitment to renewable energy* (May 2016), <https://blogs.microsoft.com/on-the-issues/2016/05/19/greener-datacenters-brighter-future-microsofts-commitment-renewable-energy/>).

¹⁰⁴¹ Omaha Public Power Initial Comments at 3.

¹⁰⁴² Dominion Reply Comments at 7–8.

¹⁰⁴³ PJM Market Monitor Initial Comments at 4.

¹⁰⁴⁴ MISO Initial Comments at 35–36.

¹⁰⁴⁵ Dominion Reply Comments at 7–8; Nebraska Commission Initial Comments at 4–5; Omaha Public Power Initial Comments at 3.

¹⁰⁴⁶ Order No. 2023, 184 FERC ¶ 61,054 at P 490.

¹⁰⁴⁷ ACEG Initial Comments at 26–29; AEE Initial Comments at 10–11; Advanced Energy Buyers Initial Comments at 5–6; Amazon Initial Comments at 3–4; Center for Biological Diversity Initial Comments at 9–12; Environmental Groups Supplemental Comments at 2; Ørsted Initial Comments at 7; Pacific Northwest State Agencies at Initial Comments at 14; PIOs Initial Comments at 18–19; SEIA Initial Comments at 10; SREA Initial Comments at 41–46; *see also* Environmental Groups Supplemental Comments at 2 ("The electric industry is undergoing a major transformation

data from state resource plans and regulatory filings.¹⁰⁵³

476. SREA and ACEG argue that the Commission should require transmission providers to incorporate utilities' generation planning announcements associated with net zero commitments and publicized utility resource plans, including SEC filings and public statements, into the development of Long-Term Scenarios.¹⁰⁵⁴ SREA contends that such a requirement would protect the interests of customers and generation developers because these announcements affect the marketplace.¹⁰⁵⁵ Breakthrough Energy suggests that utility targets and expected consumer demand should also be incorporated into the development of Long-Term Scenarios because actual demand is often higher than reflected in utility plans, which do not sufficiently incorporate corporate demand, including corporate buyer commitments.¹⁰⁵⁶

477. LADWP, MISO, and NRECA support the inclusion of this category of factors as long as transmission providers are allowed to discount these factors in their analysis by assuming the goals or commitments may not be fully met.¹⁰⁵⁷ NRECA is concerned that factor category seven (utility and corporate commitments) carries a distinct risk of stranded transmission costs and therefore supports it being discounted.¹⁰⁵⁸ NRECA further states that it is concerned that stakeholders may try to use Long-Term Regional Transmission Planning to impose goals and commitments that lack the force of law.¹⁰⁵⁹ LADWP argues that the Commission should allow transmission planners to use discretion when identifying utility commitments and local goals.¹⁰⁶⁰ MISO is concerned about the inherent difficulty of modeling corporate commitments given the ambiguous nature of corporate footprints.¹⁰⁶¹

478. Several commenters oppose including utility and corporate

commitments and/or Federal, state, and local goals as a category of factors in Long-Term Scenarios.¹⁰⁶² For example, California Commission states that it is not clear what purpose would be served by requiring transmission providers to incorporate these commitments or goals into Long-Term Scenarios yet, at the same time, allowing them to discount such commitments or goals to account for their inherent uncertainty.¹⁰⁶³ New York TOs argue that corporate commitments are amorphous and therefore should not be prescribed as a required factor for transmission providers to consider. Moreover, New York TOs state that, if a goal is not codified as a law, it is not clear that it is sufficiently solidified and supported to be included as a factor.¹⁰⁶⁴

479. PJM argues that the NOPR proposal to include corporate commitments as a factor in Long-Term Scenarios is vague, inappropriate, and impractical, because even if PJM is able to develop a record of information in the expansive PJM footprint, this information will likely be incomplete. PJM argues that the burden to ensure that a transmission provider is aware of corporate commitments and goals should be on the corporation or another interested party.¹⁰⁶⁵

480. Illinois Commission states that transmission planning criteria should not include vague terms such as "corporate goals," which could mean multiple things and may already be accounted for.¹⁰⁶⁶ Alabama Commission states that corporate commitments and goals are not a sufficient basis for planning decisions as they are not law and accountability for achieving them is limited.¹⁰⁶⁷ Similarly, Pennsylvania Commission states that determinants for Long-Term Scenarios should not be based on speculative factors, arguing that factors that include Federal, state, and local laws and regulations that affect the future resource mix and demand are preferable to factors that include utility, corporate, Federal, state, and local goals or policies that have no enforcement mechanisms.¹⁰⁶⁸ PPL states that utility and corporate commitments

are unlikely to be sufficiently firm or definitive to pass state siting review.¹⁰⁶⁹

(2) Commission Determination

481. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to incorporate Factor Category Seven: utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, in the development of Long-Term Scenarios. We find it appropriate to require transmission providers to incorporate Factor Category Seven into the development of Long-Term Scenarios because the relevant commitments and goals represent known consumer preferences that have been, and will continue to be, key drivers of Long-Term Transmission Needs. We agree with commenters that argue that corporate demand for clean energy resources, as demonstrated by the volume of bilateral corporate contracts with renewable energy resources, is already a major driver of changes in the resource mix and demand and that corporate and industrial customer demand for clean energy is projected to increase. We believe that it is necessary for transmission providers to incorporate publicly announced utility commitments in the development of Long-Term Scenarios. Such commitments may be ignored or overlooked in retail-level regulatory proceedings, but they nevertheless may have an impact on future changes in the resource mix and demand that must be accounted for to ensure the development of plausible Long-Term Scenarios.

482. We modify the NOPR proposal for Factor Category Seven to include federally-recognized Tribal goals that affect the resource mix and demand because we are persuaded by commenters that argue that such factors have the same potential to affect Long-Term Transmission Needs as Federal, state, and local goals. We believe that federally-recognized Tribal goals should include publicly announced policy recommendations, such as energy vision reports.¹⁰⁷⁰ Further, as discussed under Additional Categories of Factors below, we recognize that energy equity and justice goals are potential factors within Factor Category Seven.

¹⁰⁶⁹ PPL Initial Comments at 8.

¹⁰⁷⁰ See, e.g., Columbia River Inter-Tribal Fish Comm'n, *Energy Vision for the Columbia River Basin* (Sept. 2022), <https://critfc.org/wp-content/uploads/2022/09/CRITFC-Energy-Vision-Full-Report.pdf>.

¹⁰⁵³ SEIA Initial Comments at 10 (citing Clean Energy Buyer Association, CEBA Deal Tracker, <https://cebuyers.org/deal-tracker/>; Sierra Club, *Check Out Where We Are Ready For 100%*, <https://www.sierraclub.org/climate-and-energy/map>).

¹⁰⁵⁴ ACEG Initial Comments at 28–29; SREA Initial Comments at 41–46.

¹⁰⁵⁵ SREA Initial Comments at 41–46.

¹⁰⁵⁶ Breakthrough Energy Initial Comments at 14–15.

¹⁰⁵⁷ LADWP Initial Comments at 3; MISO Initial Comments at 36; NRECA Initial Comments at 32–33.

¹⁰⁵⁸ NRECA Initial Comments at 32 (citing GDS Assocs., Report, at 12 (Aug. 17, 2022)).

¹⁰⁵⁹ *Id.* at 32–33.

¹⁰⁶⁰ LADWP Initial Comments at 3.

¹⁰⁶¹ MISO Initial Comments at 36.

¹⁰⁶² Alabama Commission Initial Comments at 6; California Commission Initial Comments at 20; Duke Initial Comments at 13; New York TOs Initial Comments at 11–12; Pennsylvania Commission Initial Comments at 6.

¹⁰⁶³ California Commission Initial Comments at 20.

¹⁰⁶⁴ New York TOs Initial Comments at 11–12.

¹⁰⁶⁵ PJM Reply Comments at 37–38 (citing PJM Initial Comments at 68).

¹⁰⁶⁶ Illinois Commission Initial Comments at 7.

¹⁰⁶⁷ Alabama Commission Initial Comments at 6.

¹⁰⁶⁸ Pennsylvania Commission Initial Comments at 5–6.

483. While Federal, federally-recognized Tribal, state, and local goals may not have the same durability and binding impact of laws and regulations, we believe that it is appropriate for transmission providers to account for such goals in Long-Term Scenarios because these goals represent known preferences of governmental entities that affect Long-Term Transmission Needs. Such goals may improve or diminish the prospects of deploying certain technologies. For example, as AEE explains, local governments representing some of the most populous cities in the United States have established goals to have their cities' loads served by clean or renewable energy.¹⁰⁷¹

484. We disagree with commenters that argue that transmission providers should not be required to incorporate utility and corporate commitments into the development of Long-Term Scenarios because they may not be significant enough to drive Long-Term Transmission Needs or that accountability for achieving commitments and goals is too limited for these factors to be considered sufficiently firm.¹⁰⁷² We acknowledge that utility and corporate commitments and governmental goals may be more likely to change over the transmission planning horizon than factors in other required factor categories; however, we are not persuaded that these commitments and goals are so speculative, amorphous, or unreliable that they should not be incorporated into Long-Term Scenarios at all. We emphasize that transmission providers have discretion, as discussed above, in how to account for these factors in the development of Long-Term Scenarios, and we note, as discussed in further detail below, that transmission providers can account for the uncertainty associated with the achievement of these commitments and goals by using discounting or putting more weight on the effects of these factors on Long-Term Transmission Needs in each of the required Long-Term Scenarios. Similarly, transmission providers have discretion to determine how to account for commitments and goals in Long-Term Scenarios if the

effects of particular commitments or goals conflict with, negate, or duplicate the effects of other factors.

(h) Additional Categories of Factors

(1) Comments on Energy Equity and Justice

485. Some commenters argue that the Commission should include equity and energy justice considerations in Long-Term Regional Transmission Planning.¹⁰⁷³ Grand Rapids NAACP, agreeing with NASEO, urges the Commission to expand factors considered in Long-Term Regional Transmission Planning to include energy equity and justice.¹⁰⁷⁴ Grand Rapids NAACP also states that transmission providers should be required to follow Federal, state, and local laws addressing the need for energy equity and justice.¹⁰⁷⁵ In concordance with PIOs, Grand Rapids NAACP urges the Commission to address equity in the transmission planning process because doing so would encourage competition and lower consumer costs.¹⁰⁷⁶ Finally, Grand Rapids NAACP urges the Commission to encourage transmission providers to develop metrics that advance economic equity and environmental justice by facilitating consideration of the impact of transmission infrastructure on disadvantaged communities.¹⁰⁷⁷

486. US DOE asserts that energy justice considerations will form an integral part of transmission planning. Specifically, US DOE states that transmission planning can identify potential sources, sinks, and locations of transmission expansion facilities and that identifying locations where frontline communities and historically underserved communities have faced long-standing impacts may affect the future resource mix.¹⁰⁷⁸ NESCOE agrees with US DOE and argues that regional transmission planning processes should accommodate state efforts to advance equity and environmental justice concerns.¹⁰⁷⁹ New England for Offshore

Wind argues that without a transparent and inclusive transmission planning process, regional transmission planning efforts will be at odds with state policy on environmental justice.¹⁰⁸⁰

487. PIOs state that the Commission should be clear that Long-Term Regional Transmission Planning complies with and incorporates relevant aspects of applicable Federal, federally-recognized Tribal, state, and local environmental and energy justice policies—including future resource mix impacts, assignment of transmission benefits toward disadvantaged communities, and project selection.¹⁰⁸¹

488. CARE Coalition states that the Commission should consider issues of siting and the granting of permits that cause significant delays in construction of new transmission facilities.¹⁰⁸² CARE Coalition emphasizes WE ACT's argument that a final order should ensure that transmission planners and states "are cognizant about siting and the potential harms of transmission development to environmental justice communities."¹⁰⁸³ Relatedly, CARE Coalition highlights NRECA's argument that rural and poorer areas are disproportionately burdened under the current regime because "siting decisions are primarily driven by technical and economic factors."¹⁰⁸⁴

(2) Comments on Efficiency and Technology

489. NASEO argues that the Commission should expand its list of factors that transmission providers should include in Long-Term Regional Transmission Planning and Long-Term Scenarios to include increased energy efficiency of existing transmission lines, and the efficient use of existing rights of way.¹⁰⁸⁵ Invenergy suggests that the Commission expressly require consideration of advanced-stage merchant HVDC transmission as a factor in regional transmission planning scenarios.¹⁰⁸⁶ Invenergy highlights US DOE's proposal that transmission providers consider trends in the development of HVDC network technology, arguing, however, that such

¹⁰⁷¹ AEE Initial Comments at 10–11 (citing Third Way, *Utilities, Cities, and States with Clean Energy Targets* (July 30, 2021), <https://www.thirdway.org/graphic/utilities-cities-and-states-with-clean-energy-targets>).

¹⁰⁷² Alabama Commission Initial Comments at 6; California Commission Initial Comments at 20; Illinois Commission Initial Comments at 7; New York TOs Initial Comments at 11–12; Pennsylvania Commission Initial Comments at 5–6; PJM Reply Comments at 37–38 (citing PJM Initial Comments at 68); PPL Initial Comments at 8.

¹⁰⁷³ See, e.g., California Energy Commission Initial Comments at 2; City of New York Initial Comments at 9; Clean Energy Buyers Initial Comments at 8–9; Grand Rapids NAACP Initial Comments at 12, 15, 21, 23; Grand Rapids NAACP Reply Comments at 2–3, 5; Montclair Congregation Supplemental Comments at 1; NARUC Initial Comments at 3–4; NASEO Initial Comments at 5; PIOs Initial Comments at 35–36; PIOs Reply Comments at 15; Policy Integrity Initial Comments at 28; WE ACT Initial Comments at 4–6.

¹⁰⁷⁴ Grand Rapids NAACP Reply Comments at 2 (citing NASEO Initial Comments at 5).

¹⁰⁷⁵ *Id.*

¹⁰⁷⁶ *Id.* (citing PIOs Initial Comments at 35, 36).

¹⁰⁷⁷ *Id.* at 2–3 (citing NARUC Initial Comments at 3–4).

¹⁰⁷⁸ US DOE Initial Comments at 9.

¹⁰⁷⁹ NESCOE Reply Comments at 8–9.

¹⁰⁸⁰ New England for Offshore Wind Initial Comments at 5.

¹⁰⁸¹ PIOs Reply Comments at 15 (citing Grand Rapids NAACP Initial Comments at 12–15, 21–23 (listing notable Federal, state, and local public policies requiring that equity and energy justice inform decision making processes)); WE ACT Initial Comments at 6).

¹⁰⁸² CARE Coalition Reply Comments at 3.

¹⁰⁸³ *Id.* at 4 (citing WE ACT Initial Comments at 6).

¹⁰⁸⁴ *Id.* (citing NRECA Initial Comments at 39 n.111).

¹⁰⁸⁵ NASEO Initial Comments at 5.

¹⁰⁸⁶ Invenergy Initial Comments at 6–7.

consideration should include incorporating and accounting for HVDC transmission facilities in transmission planning models and scenarios.¹⁰⁸⁷

(3) Comments Regarding Enhanced Reliability and Interregional Transfer Capability

490. PJM recommends that the Commission require enhanced reliability and Interregional Transfer Capability as two additional categories of factors that transmission providers must incorporate into the development of Long-Term Scenarios.¹⁰⁸⁸ PJM envisions enhanced reliability to include, but not be limited to, storm hardening of critical facilities, reducing the number of critical CIP-014 facilities through transmission upgrades, coordination of infrastructure development with natural gas pipelines serving generation in the region, and ensuring redundancy of facilities, where appropriate, to address the threat of physical or cyber attacks.¹⁰⁸⁹ PJM envisions Interregional Transfer Capability to be established in accordance with the methodology that the Commission adopts in a subsequent order.¹⁰⁹⁰

491. Invenenergy agrees with the additional categories of factors that PJM proposes.¹⁰⁹¹ ELCON supports the consideration of transfer capability between seams, which it asserts would provide transmission providers with the ability to develop and consider solutions that may solve for multiple drivers and offer greater benefits to more consumers.¹⁰⁹² In contrast, AEE states that it disagrees with the additional categories of factors that PJM proposes, although it agrees with PJM that enhanced reliability planning is an important consideration.¹⁰⁹³

(4) Commission Determination

492. We recognize that some commenters ask the Commission to require transmission providers to incorporate several categories of factors in addition to those proposed in the NOPR in the development of Long-Term Scenarios. We decline to include energy equity and justice as a distinct and additional category of factors because we believe that these important energy equity and justice laws and regulations, or goals, that are likely to affect Long-Term Transmission Needs, are

accounted for in Factor Category One: Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand, or Seven: utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.¹⁰⁹⁴ Stakeholders will have a meaningful opportunity to identify any such factors as part of the open and transparent stakeholder process described below in the Stakeholder Process and Transparency section.

493. We decline to adopt Invenenergy's recommendation that the Commission require transmission providers to include advanced-stage merchant HVDC transmission as an additional category of factors. The Commission did not propose specific requirements in the NOPR regarding merchant HVDC transmission facilities under development, and we are not persuaded by the evidence in the record that the Commission should include advanced-stage HVDC transmission facilities in the minimum set of known determinants of Long-Term Transmission Needs. We reiterate that transmission providers may be aware of additional categories of factors beyond those adopted in this final order that drive Long-Term Transmission Needs and may incorporate additional categories of factors in the development of Long-Term Scenarios provided that each Long-Term Scenario remains plausible.

494. In response to PJM's request for the Commission to require enhanced reliability and Interregional Transfer Capability¹⁰⁹⁵ as additional categories of factors,¹⁰⁹⁶ we find that the record in this proceeding is insufficient to adequately consider whether to require transmission providers to adopt such categories of factors in this final order. As noted in our response to Invenenergy just above, transmission providers may incorporate additional categories of factors in the development of Long-

Term Scenarios provided that each Long-Term Scenario remains plausible. We note that, in this final order, we provide transmission providers with flexibility in how they develop Long-Term Scenarios to identify Long-Term Transmission Needs. We believe that other parts of this final order enable transmission providers to account for enhanced reliability and Interregional Transfer Capability by modeling sensitivities and using certain transmission benefits. As discussed below, we require transmission providers to develop at least one sensitivity analysis, applied to each Long-Term Scenario, to account for uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area that determine the benefits of or need for Long-Term Regional Transmission Facilities. As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, we require transmission providers to measure, and consider as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability that a Long-Term Regional Transmission Facility would provide.

c. Treatment of Specific Categories of Factors

i. NOPR Proposal

495. The Commission proposed to require that each Long-Term Scenario that transmission providers use in Long-Term Regional Transmission Planning incorporate and be consistent with Federal, state, and local laws and regulations that affect the future resource mix and demand; Federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans and expected supply obligations for load-serving entities. The Commission preliminarily found that it is reasonable to require transmission providers to assume that legally binding obligations and state utility regulator-approved plans will be followed and that expected supply obligations for load-serving entities will be fully met. As a result, the Commission explained that, under the proposal, transmission providers cannot discount the factors included in the categories of Federal, state, and local laws and regulations that affect the future resource mix; Federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans and expected

¹⁰⁸⁷ Invenenergy Reply Comments at 11 (citing US DOE Initial Comments at 13).

¹⁰⁸⁸ PJM Initial Comments at 6, 13, 65–67.

¹⁰⁸⁹ *Id.* at 66.

¹⁰⁹⁰ *Id.* at 66–67.

¹⁰⁹¹ Invenenergy Reply Comments at 11.

¹⁰⁹² ELCON Initial Comments at 8.

¹⁰⁹³ AEE Reply Comments at 20.

¹⁰⁹⁴ Grand Rapids NAACP Reply Comments at 2 (citing NASEO Initial Comments at 5).

¹⁰⁹⁵ We define Interregional Transfer Capability for purposes of this final order consistent with the definition of total transfer capability in the Commission's regulations as: "the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards." 18 CFR 37.6(b)(1)(vi). In the context of Interregional Transfer Capability, an "area" in the above definition would be a transmission planning region composed of transmission providers.

¹⁰⁹⁶ PJM Initial Comments at 6, 13, 65–67.

supply obligations for load-serving entities.¹⁰⁹⁷

496. In addition, the Commission proposed to require that each Long-Term Scenario that transmission providers use in Long-Term Regional Transmission Planning include trends in technology and fuel costs within and outside the electricity supply industry, including shifts toward electrification of buildings and transportation; resource retirements; and generator interconnection requests and withdrawals. For these particular categories of factors, the Commission proposed to provide transmission providers with flexibility in how they incorporate each factor into Long-Term Scenarios as long as transmission providers identify and publish specific factors for each of these categories, as further described below.¹⁰⁹⁸

497. Further, the Commission proposed to require that each Long-Term Scenario incorporate utility and corporate goals and Federal, state, and local goals that affect the future resource mix and demand. However, the Commission acknowledged that these categories of factors are less binding and more likely to change over time, and therefore their impact on the future resource mix and demand are less certain, than other categories of factors. For this reason, the Commission preliminarily found that it may be appropriate for transmission providers to discount such goals to account for this uncertainty. The Commission explained that transmission providers would not be required to assume that utility and corporate goals and Federal, state, and local goals that affect the future resource mix will be fully met.¹⁰⁹⁹

ii. Comments

498. Several commenters, that generally support the NOPR proposal, support discounting and rebut arguments opposing discounting.¹¹⁰⁰ NRECA, Exelon, and TAPS argue that the NOPR proposal to allow transmission providers to discount some categories of factors while weighing factors in other categories more heavily strikes an appropriate balance.¹¹⁰¹ Specifically, Exelon supports the NOPR

proposal to allow for variation in the treatment of different categories of factors such as legislated energy policy, which it states should not vary by scenario, and non-binding targets, which it states may be discounted yet are important to consider.¹¹⁰² TAPS also supports the proposed flexibility in how transmission providers incorporate factors that are not Federal, state, and local laws and regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities.¹¹⁰³

499. Some commenters express concerns that the NOPR proposal would allow transmission providers in each transmission planning region to discount, or not fully incorporate, some factors when developing Long-Term Scenarios.¹¹⁰⁴ Clean Energy Associations state that certain factors (*i.e.*, Federal, state, and local policies, utility integrated resource plans, generator retirements, interconnection requests, corporate commitments, and trends in technology and fuel costs) can be quantified and should be reflected in Long-Term Scenarios without discounting.¹¹⁰⁵ Clean Energy Buyers are concerned that the flexibility proposed in the NOPR for transmission providers to incorporate into their Long-Term Scenarios the categories of factors that include trends in fuel costs and technologies both inside and outside the electricity supply industry, including regarding shifts in electrification of transport and buildings, resource retirements, and generator interconnection requests and withdrawals, could delay the transmission build-out.¹¹⁰⁶ ACEG recommends that the Commission presume that all factors are required to be incorporated (and not discounted or only considered) unless the Commission approves a request from the transmission providers in a transmission planning region not to include a factor.¹¹⁰⁷ In response, California Municipal Utilities argue that mandating the use of specific factors would not account for the cost consequences of such mandates, which must be considered for any transmission

planning requirements to be just and reasonable.¹¹⁰⁸

500. Several commenters object to the Commission's proposal to provide transmission providers with the flexibility to discount utility and corporate and Federal, state, and local goals that affect the future resource mix and demand.¹¹⁰⁹ Amazon states that transmission providers should not be allowed to discount clean energy goals in their development of Long-Term Scenarios without proving such discounting is just and reasonable by showing evidence that such goals have been unfulfilled in the past, or that those goals have been altered or abandoned.¹¹¹⁰

501. PIOs state that the NOPR proposal to discount Factor Category Seven would allow transmission providers to game the results if their incentives are contrary to consumers' goals.¹¹¹¹ SEIA urges the Commission to limit the flexibility given to transmission providers regarding this factor because SEIA believes that they would ignore certain factors if consideration is not mandatory.¹¹¹² Further, Clean Energy Associations argue that utility, corporate, and Federal, state, and local goals should be fully incorporated, without discounting targets not enshrined in law or regulation. If necessary, Clean Energy Associations contend, changes in non-binding obligations could be treated as a sensitivity or probabilistic change in one or more scenarios to determine how they might affect transmission development.¹¹¹³

502. PIOs state that, when utilities make commitments affecting the future resource mix and consumer demand, they should be held to them and that granting transmission providers complete discretion to discount such factors could undermine the goals of the NOPR proposal. Thus, PIOs state, the Commission should set minimum requirements for some factors, including for incorporating corporate commitments into future resource mix estimates.¹¹¹⁴ PIOs assert that widespread support exists for these

¹⁰⁹⁷ NOPR, 179 FERC ¶ 61,028 at P 106.

¹⁰⁹⁸ *Id.* P 107.

¹⁰⁹⁹ *Id.* P 108.

¹¹⁰⁰ Exelon Initial Comments at 10–11; Georgia Commission Initial Comments at 4; Illinois Commission Initial Comments at 7; NEPOOL Initial Comments at 7; NRECA Initial Comments at 32; TAPS Initial Comments at 2–3, 8.

¹¹⁰¹ Exelon Initial Comments at 10–11; NRECA Initial Comments at 32; TAPS Initial Comments at 2–3, 8.

¹¹⁰² Exelon Initial Comments at 10–11.

¹¹⁰³ TAPS Initial Comments at 2–3, 8.

¹¹⁰⁴ ACEG Initial Comments at 27–28; Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10–11; Pine Gate Initial Comments at 23–25; PIOs Initial Comments at 18–19; SEIA Initial Comments at 8–10.

¹¹⁰⁵ Clean Energy Associations Initial Comments at 10–11.

¹¹⁰⁶ Clean Energy Buyers Initial Comments at 15–16.

¹¹⁰⁷ ACEG Initial Comments at 27.

¹¹⁰⁸ California Municipal Utilities Reply Comments at 5–6.

¹¹⁰⁹ Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10–11; Pine Gate Initial Comments at 24–25; PIOs Initial Comments at 18–19; SEIA Initial Comments at 8.

¹¹¹⁰ Amazon Initial Comments at 4.

¹¹¹¹ PIOs Initial Comments at 18–19.

¹¹¹² SEIA Initial Comments at 8.

¹¹¹³ Clean Energy Associations Initial Comments at 10–11.

¹¹¹⁴ PIOs Initial Comments at 17–18.

recommendations, citing ELCON as an example.¹¹¹⁵

503. Pine Gate argues that transmission providers should be required to assume that utility and corporate and Federal, state, and local goals that affect the future resource mix will be fully met in at least one of their Long-Term Scenarios.¹¹¹⁶

504. In addition, Pattern Energy argues that the Commission should distinguish between generation assumptions and demand assumptions for purposes of 20-year transmission planning so that there is no ambiguity. For example, Pattern Energy states that transmission providers should not be permitted to utilize their planning for load growth to satisfy the requirement to plan for changing resources and demand. Pattern Energy asserts that transmission providers should be required to distinguish between modeling a changing resource mix and, separately, a changing demand profile, arguing that both are important and should be considerations in near-term and long-term transmission planning.¹¹¹⁷

505. NYISO argues that the final order should permit transmission providers to appropriately account for, in coordination with state and local entities and stakeholders, the likely effect of applicable laws and regulations on the need for transmission and to realistically appraise achievement of such laws and regulations.¹¹¹⁸

506. Some commenters oppose the NOPR proposal to require that transmission providers incorporate applicable local laws and regulations in their development of Long-Term Scenarios.¹¹¹⁹ Duke explains that although local laws and regulations for decarbonization and electrification may affect the resource mix and demand at the local level, it is unclear how such laws would have a material effect on regional transmission planning that warrants the additional burden of tracking and incorporating them into Long-Term Scenarios.¹¹²⁰ Alabama Commission argues that local laws, regulations, and goals might change or conflict with the policy perspectives of other states.¹¹²¹ PPL claims that the

NOPR proposal is impractical and will significantly increase uncertainty, which in turn will invite disagreement and litigation.¹¹²² PJM recommends that the Commission require transmission providers to only consider local laws, local regulations, and local goals to the extent that such laws, regulations, and goals are brought to their attention by states, other local regulators, or stakeholders.¹¹²³

iii. Commission Determination

(a) Treatment of Factors in the First Three Categories

507. With regard to the first three categories of factors,¹¹²⁴ we require transmission providers in each transmission planning region to assume that legally binding obligations (*i.e.*, Federal, federally-recognized Tribal, state, and local laws and regulations) are followed, state-approved integrated resource plans are followed, and expected supply obligations for load-serving entities are fully met. Therefore, we require that each Long-Term Scenario account for and be consistent with, and not discount, factors in the first three categories of factors once the transmission providers have determined that such a factor is likely to affect Long-Term Transmission Needs. We believe it is necessary to prohibit discounting of factors in the first three categories of factors because they are more certain drivers of Long-Term Transmission Needs, relative to factors in other factor categories.

508. We clarify that transmission providers may rely on the open and transparent stakeholder process discussed below to identify the factors in the first three required categories of factors. More specifically, this final order does not obligate transmission providers to independently identify all of the factors in the first three categories of factors. We believe that it would be unduly burdensome and potentially impractical for transmission providers to independently identify all of the potential factors in the first three categories of factors, which will include numerous Federal, federally-recognized Tribal, state, and local laws and regulations, as well as integrated

resource plans and expected supply obligations for load-serving entities.¹¹²⁵ However, transmission providers may, if they choose, independently identify factors in the first three categories of factors as part of the stakeholder process, discussed further in the Stakeholder Process and Transparency section below.

509. We believe that this clarification addresses PJM's request that we clarify that the burden of making the transmission provider aware of laws, regulations, and goals rests with stakeholders and not with the transmission provider itself.¹¹²⁶ We also believe that this clarification mitigates the potential administrative burdens and compliance risks identified by ISO-NE, as well as the burden of incorporating factors identified by SPP.¹¹²⁷

510. In addition, as clarified above, transmission providers retain the discretion to determine whether particular factors, including those in the first three categories of factors, that stakeholders identify are likely to affect Long-Term Transmission Needs. Thus, transmission providers may determine, for example, that some stakeholder-identified local laws and regulations that fall within Factor Categories One and Two are unlikely to affect Long-Term Transmission Needs and therefore need not be accounted for in the development of Long-Term Scenarios. We believe that this clarification addresses concerns about the additional burden some commenters identified of tracking and incorporating local laws and regulations into the development of Long-Term Scenarios, as well as concerns that the inclusion of local laws and regulations in the first two categories of factors creates a burden for transmission providers to account for factors that are unlikely to affect Long-Term Transmission Needs.¹¹²⁸

511. We believe that the open and transparent stakeholder process

¹¹¹⁵ PIOs Reply Comments at 10–11 (citing ELCON Initial Comments at 4).

¹¹¹⁶ Pine Gate Initial Comments at 25.

¹¹¹⁷ Pattern Energy Initial Comments at 26.

¹¹¹⁸ NYISO Initial Comments at 23.

¹¹¹⁹ Alabama Commission Initial Comments at 5–6; Ameren Initial Comments at 9–10; Duke Initial Comments at 13–14, 16; ISO-NE Initial Comments at 26–27; ISO/RTO Council Initial Comments at 4–5; NYISO Initial Comments at 21–23.

¹¹²⁰ Duke Initial Comments at 13.

¹¹²¹ Alabama Commission Initial Comments at 5–6.

¹¹²² PPL Initial Comments at 7–8.

¹¹²³ PJM Reply Comments at 38 (citing PJM Initial Comments at 68).

¹¹²⁴ As explained above, the first three categories of factors are: (1) Federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand; (2) Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; and (3) state-approved integrated resource plans and expected supply obligations for load-serving entities.

¹¹²⁵ The Commission has previously found that transmission providers “cannot later be faulted” for failing to consider projections of a need for service from a point-to-point transmission customer if such projections are not provided by the transmission customer. Order No. 890, 118 FERC ¶ 61,119 at P 487; *id.* (“We also believe that it is appropriate to require point-to-point customers to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points If the point-to-point customers do not submit such projections, then the transmission provider cannot later be faulted for failing to consider planning scenarios that might have taken into account reasonable projections of future system uses that were not the subject of specific service requests.”).

¹¹²⁶ PJM Initial Comments at 68.

¹¹²⁷ ISO-NE Initial Comments at 26–27; SPP Initial Comments at 7–8.

¹¹²⁸ Duke Initial Comments at 13.

discussed below in the Stakeholder Process and Transparency section will help transmission providers to ensure that each Long-Term Scenario accounts for factors in the first three categories of factors without discounting the effects of those factors on Long-Term Transmission Needs. We expect that transmission providers will rely, at least in part, on information that relevant Federal, state, and local government entities, federally-recognized Tribes, utilities, and load-serving entities provide during the required open and transparent stakeholder process to determine if specific factors are likely to affect Long-Term Transmission Needs and how to account for those specific factors in Long-Term Scenarios. We agree with NYISO regarding the value of coordination and clarify that transmission providers may work in coordination with government entities and stakeholders to determine how applicable laws and regulations may affect Long-Term Transmission Needs.¹¹²⁹

512. We recognize that some commenters raise concerns as to whether factors in the first three categories of factors can be fully achieved (*e.g.*, a legislative requirement is met) or may have various levels of impact on Long-Term Transmission Needs.¹¹³⁰ At the outset, we find it appropriate to assume legally binding obligations are met, unless and until there is a change in law. Government entities have an interest and ability to ensure that the requirements of laws and regulations are fully achieved. Similarly, utilities and load-serving entities, as well as the relevant retail regulator, have an interest in developing accurate integrated resource plans and expected supply obligations that can be fully achieved. Even in the limited circumstances in which these factors are not fully achieved, we expect the targets or requirements associated with these factors will be informative for purposes of identifying Long-Term Transmission Needs. We acknowledge that, for certain factors, there may be insufficient information for transmission providers to determine, or stakeholder disagreement about, how the factor will affect Long-Term Transmission Needs. In such instances, we clarify that transmission providers have discretion over how to account for a factor in the first three categories of factors in their Long-Term Scenarios as long as the assumptions in each Long-Term Scenario are consistent with legally binding obligations, state-approved

integrated resource plans, and expected supply obligations of load-serving entities.

513. For example, when a legally binding obligation sets a minimum requirement or threshold (*e.g.*, a state law requiring the deployment of at least 5 gigawatts of electric storage resources by 2030), transmission providers may develop Long-Term Scenarios assuming either the minimum amount of the requirement or more than the minimum amount of the requirement (*e.g.*, modeling 10 gigawatts of electric storage resources deployed by 2030 instead of the minimum 5 gigawatts) but may not develop any Long-Term Scenarios that are inconsistent with that minimum (*e.g.*, modeling only 2 gigawatts of electric storage resources deployed by 2030). We believe that these clarifications sufficiently address PPL's concerns regarding the uncertainty associated with how transmission providers are expected to translate factors, including local laws and regulations, into Long-Term Scenarios.¹¹³¹ We note that the requirement, discussed further below, that Long-Term Scenarios be plausible and diverse also clarifies how transmission providers must account for factors in the Long-Term Scenarios. That is, while transmission providers can model assumptions that exceed the minimum requirements of factors in the first three categories in developing Long-Term Scenarios, they can only exceed those minimum requirements such that each Long-Term Scenario remains plausible.¹¹³² Similarly, the requirement that Long-Term Scenarios be diverse ensures that transmission providers will model the effect of factors on Long Term Transmission Needs in different ways, and thus that Long-Term Scenarios help to manage uncertainty over how factors will affect Long-Term Transmission Needs.

514. We disagree with ISO-NE's claim that requiring that each Long-Term Scenario account for and consistently reflect the first three categories of factors would unnecessarily prevent testing of variations with these categories of factors. Where a factor's effect is not clear on its face, transmission providers have discretion, within reason, to determine the likely effect of full achievement of the factor and reflect that into development of the Long-Term Scenarios. Transmission providers also

are not limited to assuming only the minimum requirements of a factor are fully achieved in developing the Long-Term Scenarios.

515. We also are unpersuaded by commenter claims that local laws and regulations might conflict with state laws and regulations and, therefore, we should not include local laws and regulations in the first two categories of factors.¹¹³³ However, we acknowledge that there may be limited circumstances when two legally binding factors have conflicting or opposite implications for Long-Term Transmission Needs. We clarify that, in such circumstances, transmission providers shall reconcile this information while giving full effect to the maximum extent possible to all legally binding factors. For example, where two laws have equal and opposite effect, transmission providers may need to incorporate them as negating each other, as necessary to comply with the requirement to produce plausible Long-Term Scenarios. In circumstances when that is not possible because the legally binding factors support alternatives to the same assumption used to develop Long-Term Scenarios, transmission providers could use two or more of the three required Long-Term Scenarios, or develop additional Long-Term Scenarios, to capture the differences implied by each of the conflicting factors.

(b) Treatment of Factors in the Last Four Categories

516. We affirm that transmission providers have additional discretion in how they account for each factor in the last four categories of factors compared to how they account for each factor in the first three categories.¹¹³⁴ After transmission providers have determined that a specific factor, stakeholder-identified or otherwise, is likely to affect Long-Term Transmission Needs over the transmission planning horizon, transmission providers must then assess the extent to which the anticipated effects on Long-Term Transmission Needs due to that factor are likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios. For example, for a corporate commitment

¹¹³³ Alabama Commission Initial Comments at 5–6; PJM Initial Comments at 68.

¹¹³⁴ As explained above, the last four categories of factors are: (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; (7) utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs.

¹¹³¹ PPL Initial Comments at 8.

¹¹³² Likewise, as discussed in the Treatment of Factors in the Last Four Categories section, transmission providers may only discount the effect of factors in the last four categories on Long-Term Transmission Needs such that each Long-Term Scenario remains plausible.

¹¹²⁹ NYISO Initial Comments at 23.

¹¹³⁰ *Id.*

identified in Factor Category Seven, transmission providers can make a determination that only a fraction of that corporate commitment will actually be met, and the transmission providers can subsequently model more limited effects on Long-Term Transmission Needs due to that factor, in some or all Long-Term Scenarios. Likewise, transmission providers may put more weight on the factor by modeling more than the projected change in some or all Long-Term Scenarios to reflect the transmission providers' view regarding the likelihood that the anticipated effects on Long-Term Transmission Needs due to that factor will occur. Transmission providers may choose to discount or put more weight on the effects on Long-Term Transmission Needs due to factors in Factor Categories Four through Seven to account for uncertainty when developing plausible and diverse Long-Term Scenarios.

517. Several commenters generally support this flexibility to treat the last four categories of factors differently from the first three.¹¹³⁵ We believe that requiring transmission providers to incorporate the last four categories of factors, but allowing transmission providers to discount the effects of factors within these categories, strikes an appropriate balance between requiring factors in these categories be given full weight, and allowing them to be excluded entirely in developing Long-Term Scenarios. We believe that these categories of factors affect Long-Term Transmission Needs, and absent a requirement to incorporate them, transmission providers may fail to identify, evaluate, and select more efficient or cost-effective Long-Term Regional Transmission Facilities to address those Long-Term Transmission Needs. On the other hand, these categories of factors are less certain than the first three categories and should not necessarily be given the same weight in developing Long-Term Scenarios as factors that are legally binding.

518. We disagree with the concern that this flexibility could allow transmission providers to ignore the last four factor categories¹¹³⁶ because the final order requires transmission providers to incorporate all categories of factors in each Long-Term Scenario,

even if they discount specific factors within the category, and requires that all Long-Term Scenarios be plausible.¹¹³⁷ We reiterate that transmission providers may only discount the effects of factors in these categories on Long-Term Transmission Needs such that each Long-Term Scenario remains plausible.

d. Stakeholder Process and Transparency

i. NOPR Proposal

519. The Commission proposed to require that transmission providers identify and publish on an Open Access Same-Time Information System (OASIS) or other public website a list of the factors that fall into each of the required categories of factors that they will incorporate in their development of Long-Term Scenarios. The Commission explained that transmission providers would be responsible for identifying all the factors they know of and are considering incorporating in the development of Long-Term Scenarios as part of Long-Term Regional Transmission Planning. The Commission also proposed to require transmission providers to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose potential factors that transmission providers must incorporate in their development of Long-Term Scenarios, such as specific laws, regulations, goals, and commitments, and to provide input on how to appropriately discount factors that are less certain.¹¹³⁸

520. The Commission noted that, under Order No. 1000, transmission providers must already have procedures in their OATTs that give stakeholders a meaningful opportunity to submit proposed transmission needs driven by Public Policy Requirements and that allow transmission providers to identify, out of the larger set of potential transmission needs driven by Public Policy Requirements that stakeholders propose, those needs for which transmission facilities will be evaluated.¹¹³⁹ Therefore, the Commission explained that transmission providers may be able to modify and expand these existing procedures for identifying transmission needs driven by Public Policy

Requirements to meet these proposed requirements regarding the identification of factors for incorporation into Long-Term Scenarios.¹¹⁴⁰

ii. Comments

(a) State Input

521. Several commenters emphasize the important role of stakeholders, including states, in identifying or commenting on the factors to be included in the development of Long-Term Scenarios.¹¹⁴¹ In addition, Southeast PIOs note that states do not currently engage in regional transmission planning processes to any meaningful degree, and therefore, the Commission should encourage their participation in shaping and conducting Long-Term Regional Transmission Planning.¹¹⁴²

522. Some commenters discuss the important role of states in identifying factors within specific category of factors.¹¹⁴³ DC and MD Offices of People's Counsel assert that the final order should explicitly require information on the factors to be provided by appropriate authorities, such as state agencies.¹¹⁴⁴ New Jersey Commission supports the Commission's proposal to require that states have a meaningful opportunity to propose potential factors to be incorporated into the development of Long-Term Scenarios and to provide input on appropriately discounting less certain factors.¹¹⁴⁵ NESCOE asserts that, if states do not play a central role in determining the factors, the proposed reforms will likely run into the problem that underlies the Order No. 1000 public policy transmission planning process in New England, where states do not have a decision-making role over project selection even though state laws or policies could be the driver for the project.¹¹⁴⁶

523. However, other commenters state that their existing processes are adequate for determining the relevant factors to include in Long-Term

¹¹⁴⁰ *Id.*

¹¹⁴¹ APPA Initial Comments at 27–29; PIOs Initial Comments at 22; PJM Initial Comments at 70; Southeast PIOs Initial Comments at 45, 46–47.

¹¹⁴² Southeast PIOs Initial Comments at 45–46; State Officials Supplemental Comments at 1.

¹¹⁴³ DC and MD Offices of People's Counsel Initial Comments at 12; New Jersey Commission Initial Comments at 14–15.

¹¹⁴⁴ DC and MD Offices of People's Counsel Initial Comments at 12.

¹¹⁴⁵ New Jersey Commission Initial Comments at 14–15.

¹¹⁴⁶ NESCOE Initial Comments at 28–29.

¹¹³⁵ APPA Initial Comments at 27–28; Exelon Initial Comments at 10–11 (citing NOPR, 179 FERC ¶ 61,028 at P 121); NRECA Initial Comments at 29–32; TAPS Initial Comments at 2–3, 8.

¹¹³⁶ *E.g.*, ACEG Initial Comments at 27–28; Amazon Initial Comments at 4; Clean Energy Associations Initial Comments at 10–11; Pine Gate Initial Comments at 23–25; PIOs Initial Comments at 18–19; SEIA Initial Comments at 8–10.

¹¹³⁷ ACEG Initial Comments at 28; DC and MD Offices of People's Counsel Initial Comments at 11.

¹¹³⁸ NOPR, 179 FERC ¶ 61,028 at P 109.

¹¹³⁹ *Id.* P 110 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 206–207; Order No. 1000–A, 139 FERC ¶ 61,132 at P 335).

Regional Transmission Planning.¹¹⁴⁷ PJM states that it currently has processes and standing committees that allow states and stakeholders to participate in discussions of factors to use in its transmission planning processes. For example, PJM asserts that its Independent State Agencies Committee is set up to receive feedback on transmission planning from states, and it discusses, among other things, assumptions used in the models, relevant regulatory initiatives and their impact, and alternative sensitivities, as well as what was discussed at other committee meetings. In addition, PJM states, it vets all proposed transmission solutions with its Transmission Expansion Advisory Committee before submitting them to the PJM board for approval.¹¹⁴⁸

(b) Transparency, Enforcement, and Accuracy

524. Cross Sector Representatives state that Long-Term Regional Transmission Planning processes should provide transparency for impacted stakeholders.¹¹⁴⁹ SEIA argues that the Commission should adopt clear, uniform language that sets forth the specific goals and deliverables from the proposed Long-Term Regional Transmission Planning process for transmission providers to include in their tariffs, including language that mirrors the proposed list of categories of factors the Commission included in the NOPR.¹¹⁵⁰

525. Several commenters support the NOPR proposal to require transmission providers to post the list of factors that they will incorporate into their Long-Term Scenarios on a public website for stakeholder comment.¹¹⁵¹ Pine Gate recommends that the Commission further require that transmission providers identify and publish all factors that were considered but not incorporated.¹¹⁵²

526. Clean Energy Buyers state that, to ensure transparency and just and reasonable rates, the Commission should require that transmission providers post the details regarding any proposed or adopted discounting of factors on OASIS, including: (1) which

factors are to be discounted; (2) the extent of the discounting; and (3) the justification for and derivation of the amount of discounting deemed appropriate.¹¹⁵³

527. GridLab and R Street propose modifications to the NOPR proposal regarding the role of stakeholders.¹¹⁵⁴ GridLab proposes that state agencies, other stakeholders, and independent experts could play a dominant role in enforcing the Commission's requirement to incorporate specific categories of factors, and that the Commission would provide a common framework establishing guidelines on the kinds of factors that transmission providers should consider, at a minimum, in developing Long-Term Scenarios.¹¹⁵⁵ In addition, R Street argues that governance mechanisms should drive the selection of data sets, methods, and assumptions behind these factors to promote objective accuracy.¹¹⁵⁶

iii. Commission Determination

528. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including federally-recognized Tribes and states, with a meaningful opportunity to propose potential factors and to provide timely input on how to account for specific factors in the development of Long-Term Scenarios.¹¹⁵⁷ As discussed below, we also adopt the NOPR proposal, with modification, to require transmission providers to publish on the public portion of an OASIS or other public website: (1) the list of the factors in each of the seven required categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each of those factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each Long-Term Scenario; and (5) a

list of the factors that they considered but did not incorporate in their Long-Term Scenarios.

529. We believe that a robust stakeholder process will ensure that transmission providers can identify which, and how, specific factors might influence Long-Term Transmission Needs over the transmission planning horizon. For this reason, consistent with Order No. 890's transmission planning principles,¹¹⁵⁸ we require transmission providers to give stakeholders a meaningful opportunity to provide timely input on how and what information to incorporate in Long-Term Scenarios, including how to account for a specific factor in terms of how the factor may affect Long-Term Transmission Needs. We clarify that this meaningful opportunity for stakeholders to provide timely input includes the opportunity to propose factors, provide information and identify sources of best available data, propose how a factor may affect Long-Term Transmission Needs, and explain how that factor could be reflected in the development of Long-Term Scenarios, including the extent to which it is appropriate to discount the effects of certain factors on Long-Term Transmission Needs. We note that some transmission providers have existing processes in place that allow states and stakeholders to participate in discussions of factors, which transmission providers can propose, with any necessary modifications, to comply with this final order.¹¹⁵⁹

530. We believe that affording stakeholders a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios will help transmission providers to develop more accurate assumptions to serve as the basis for their Long-Term Scenarios. Specifically, with stakeholder input, transmission providers will be in a better position to determine which specific factors within each category of factors they should account for in the development of Long-Term Scenarios, as well as how best to incorporate them. Stakeholder input is particularly important for factors in the first three categories of factors because Federal, state, and local government entities, federally-recognized Tribes, and utilities, load-serving entities, and their retail regulators that participate in the stakeholder process are distinctly

¹¹⁴⁷ MISO Initial Comments at 34–35; MISO TOs Initial Comments at 18; OMS Initial Comments at 6; PJM Initial Comments at 6, 64, 70–71.

¹¹⁴⁸ PJM Initial Comments at 70–71.

¹¹⁴⁹ Cross Sector Representatives Supplemental Comments at 1.

¹¹⁵⁰ SEIA Reply Comments at 3–4 (citing PJM Initial Comments at 27–28).

¹¹⁵¹ Ameren Initial Comments at 11–12; APPA Initial Comments at 28; NESCOE Initial Comments at 28; Pine Gate Initial Comments at 25; PIOs Initial Comments at 22.

¹¹⁵² Pine Gate Initial Comments at 25.

¹¹⁵³ Clean Energy Buyers Initial Comments at 16–17.

¹¹⁵⁴ GridLab Initial Comments at 20–21; R Street Initial Comments at 7.

¹¹⁵⁵ GridLab Initial Comments at 21.

¹¹⁵⁶ R Street Initial Comments at 7.

¹¹⁵⁷ As an example, transmission providers would provide stakeholders with an opportunity to describe how a specific state law in the first category of factors will result in the development of new resources of a certain type, the retirement of existing resources, or changes in demand patterns due to increased electrification.

¹¹⁵⁸ See, e.g., Order No. 890, 118 FERC ¶61,119 at P 454.

¹¹⁵⁹ MISO Initial Comments at 34–35; PJM Initial Comments at 6, 64, 70–71.

positioned to provide transmission providers with vital information on how the factors over which they have authority or govern are likely to influence Long-Term Transmission Needs over the transmission planning horizon. Similarly, utilities, corporations, and governments that participate in the stakeholder process are distinctly positioned to provide transmission providers with vital information regarding factors in Factor Category Seven: utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs. The required stakeholder process ensures that all stakeholders, including states, can provide important and useful information concerning factors that they believe will affect Long-Term Transmission Needs.

531. We recognize that different stakeholders may provide information about the same factor that is contradictory—an issue identified by some commenters.¹¹⁶⁰ Different stakeholders may also provide different analyses showing, for example, how a specific factor will affect resource additions and retirements. However, as we explain earlier, transmission providers have discretion regarding how to account for specific factors in their development of Long-Term Scenarios. In reviewing the information provided by stakeholders in the open and transparent stakeholder process, transmission providers may weigh more heavily one source of information over another. To maintain transparency for stakeholders, transmission providers must include a general statement explaining how they will account for each factor in their Long-Term Scenarios on the public portion of an OASIS or other public website, as further described below.

532. We also believe that the information provided in the open and transparent stakeholder process will reduce the burden placed on transmission providers to identify and assess the impact of relevant factors for each category. For example, transmission providers can rely on the open and transparent stakeholder process to identify the multiple relevant local laws and regulations that are likely to influence Long-Term Transmission Needs over the transmission planning horizon. The same is true for the utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect

Long-Term Transmission Needs in Factor Category Seven. During the stakeholder process, government entities, utilities, and corporate entities can identify their publicly announced goals and provide feedback on how the transmission providers can account for these publicly announced goals in Long-Term Scenarios. These entities will have an opportunity to provide information to help the transmission providers determine the likelihood that they will achieve their stated goals, which the transmission providers can then use to discount the specific factors in Factor Category Seven, if necessary.

533. With regard to the information about factors and categories of factors that transmission providers must publish on the public portion of an OASIS or other public website, we modify the proposal in the NOPR. We require transmission providers to publish on the public portion of an OASIS or other public website: (1) the list of the factors in each of the seven required categories of factors that they will account for in their Long-Term Scenarios; (2) a description of each factor that they will account for in their Long-Term Scenarios; (3) a general statement explaining how they will account for each of these factors in their Long-Term Scenarios; (4) a description of the extent to which they will discount any factors in Factor Categories Four through Seven in each Long-Term Scenario; and (5) a list of the factors that they considered but did not incorporate in their Long-Term Scenarios.¹¹⁶¹ Transmission providers must post this information after stakeholders, including states, have had the meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios.

534. We believe that this transparency is necessary to make clear to stakeholders which specific factors transmission providers incorporate into Long-Term Scenarios and how they incorporate those factors. We believe the posting requirement will also provide greater transparency into how transmission providers develop Long-Term Scenarios (discussed below), as some commenters requested, while still providing transmission providers with flexibility regarding whether, and if so, how they choose to incorporate relevant factors.

535. In response to commenters requesting additional transparency,¹¹⁶² we require transmission providers to publish on the public portion of an OASIS or other public website the factors that were considered but not accounted for in the development of Long-Term Scenarios. We believe this requirement will help stakeholders understand which factors, either identified in the stakeholder process or independently identified by a transmission provider, the transmission providers in a transmission planning region have determined are unlikely to affect Long-Term Transmission Needs. This transparency also ensures that stakeholder-proposed factors are reviewed in a fair and non-discriminatory manner.

536. We decline to require transmission providers to publicly publish the justification for and derivation of the amount of discounting deemed appropriate, as requested by Clean Energy Buyers.¹¹⁶³ We believe such a requirement to detail the rationale for the treatment of each factor in Factor Categories Four through Seven, across all Long-Term Scenarios, would create a time-consuming administrative burden for transmission providers that is not justified by the value of the additional information provided to stakeholders.

537. We decline to adopt modifications to the NOPR proposal that would diminish the role of the transmission providers in developing Long-Term Scenarios.¹¹⁶⁴ Transmission providers must provide stakeholders with a meaningful opportunity to propose potential factors and to provide input on how to incorporate specific factors in the development of Long-Term Scenarios, as described above. However, we reiterate that transmission providers are not required to incorporate stakeholder-identified factors into their development of Long-Term Scenarios merely because stakeholders propose them, if transmission providers determine that the factor is unlikely to influence Long-Term Transmission Needs over the transmission planning horizon. Consistent with Order No. 890, the ultimate responsibility for transmission planning remains with the transmission provider.¹¹⁶⁵

¹¹⁶² E.g., Pine Gate Initial Comments at 25.

¹¹⁶³ Clean Energy Buyers Initial Comments at 16–17.

¹¹⁶⁴ E.g., GridLab Initial Comments at 20–21; R Street Initial Comments at 7.

¹¹⁶⁵ Order No. 890, 118 FERC ¶ 61,119 at P 454.

There, in response to the suggestion by some commenters that we require transmission providers

¹¹⁶⁰ E.g., Undersigned States Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at P 106).

¹¹⁶¹ As discussed above, transmission providers may not discount factors in Factor Categories One through Three.

4. Number and Development of Long-Term Scenarios

a. NOPR Proposal

538. In the NOPR, the Commission proposed to require transmission providers to develop at least four distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning at least once during a transmission planning cycle.¹¹⁶⁶ The Commission explained that it preliminarily found that using at least four distinct Long-Term Scenarios is a reasonable lower bound for the number of Long-Term Scenarios that transmission providers must evaluate in Long-Term Regional Transmission Planning. The Commission explained that this minimum number of Long-Term Scenarios would help to ensure that transmission providers conduct Long-Term Regional Transmission Planning that identifies more efficient or cost-effective regional transmission facilities to meet transmission needs driven by changes in the resource mix and demand. The Commission explained that to satisfy this requirement, transmission providers could develop a base case and three alternatives, or a low-, medium-, and high-level assumption for the factors that transmission providers (and their stakeholders) believe to be important to conduct Long-Term Regional Transmission Planning to more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand, along with a scenario that accounts for a high-impact, low-frequency event (as discussed below).¹¹⁶⁷

539. Consistent with the Order No. 890 transparency transmission planning principle,¹¹⁶⁸ the Commission proposed to require transmission providers in

to allow customers to collaboratively develop transmission plans with transmission providers on a co-equal basis, we clarified that transmission planning is the tariff obligation of each transmission provider, and the *pro forma* OATT planning process adopted in this final rule is the means to see that it is carried out in a coordinated, open, and transparent manner, in order to ensure that customers are treated comparably. Therefore, the ultimate responsibility for planning remains with transmission providers.

¹¹⁶⁶ NOPR, 179 FERC ¶ 61,028 at PP 121–126.

¹¹⁶⁷ *Id.* P 122.

¹¹⁶⁸ The transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

each transmission planning region to publicly disclose (subject to any applicable confidentiality protections) information and data inputs they use to create each Long-Term Scenario. The Commission explained that this transparency requirement will allow stakeholders to understand how each scenario differs.

540. Similarly, consistent with the coordination transmission planning principle established in Order No. 890,¹¹⁶⁹ the Commission proposed to require that transmission providers in each transmission planning region give stakeholders the opportunity to provide timely and meaningful input into the identification of which Long-Term Scenarios are developed. The Commission proposed to require transmission providers to revise the regional transmission planning processes in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios. Furthermore, the Commission proposed to require transmission providers to explain on compliance how their process will identify a plausible and diverse set of Long-Term Scenarios.¹¹⁷⁰

b. Comments

541. Many commenters support requiring transmission providers in each transmission planning region to develop at least four distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning.¹¹⁷¹ GridLab and

¹¹⁶⁹ The coordination transmission planning principle requires transmission providers to provide customers and other stakeholders with the opportunity to participate fully in the transmission planning process. The transmission planning process must provide for the timely and meaningful input and participation of customers and other stakeholders regarding the development of transmission plans, allowing customers and other stakeholders to participate in the early stages of development. Order No. 890, 118 FERC ¶ 61,119 at PP 451–454.

¹¹⁷⁰ NOPR, 179 FERC ¶ 61,028 at P 123.

¹¹⁷¹ ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 8; AEE Initial Comments at 8, 18; APPA Initial Comments at 29; Arizona Commission Initial Comments at 6; Concerned Scientists Reply Comments at 18–19; ELCON Initial Comments at 12; ENGIE Initial Comments at 4; Evergreen Action Initial Comments at 3; Georgia Commission Initial Comments at 4–5; GridLab Initial Comments at 12; ITC Initial Comments at 12; Nevada Commission Initial Comments at 8–9; New England for Offshore Wind Initial Comments at 2; NextEra Initial Comments at 65; Northwest and Intermountain Initial Comments at 12; NYISO Initial Comments at 25; Ørsted Initial Comments at 7; Southeast PIOs Initial Comments at 46; SPP Market Monitor Initial Comments at 6–7; US Chamber of Commerce Initial Comments at 7;

R Street state that this proposed requirement appropriately balances the need to address uncertainty and risk factors associated with long-term transmission planning while limiting the complexity of the transmission planning process.¹¹⁷² PJM says that employing multiple scenarios will ensure that transmission providers' plans reflect changing needs while avoiding the risk of over-building.¹¹⁷³ SEIA states that requiring four distinct Long-Term Scenarios will allow transmission providers to reflect the uncertainty inherent in long-term planning.¹¹⁷⁴ AEE states that the Commission should establish a minimum number of scenarios as a baseline for compliance with any final order.¹¹⁷⁵ New York TOs support requiring the use of multiple scenarios for Long-Term Regional Transmission Planning, noting that NYISO already incorporates multiple scenarios into its transmission planning processes.¹¹⁷⁶ Nevada Commission notes that information from four scenarios could provide inputs into Nevada's integrated regional planning process and identify both local and regional needs.¹¹⁷⁷

542. Policy Integrity argues that the Commission should require more than four Long-Term Scenarios.¹¹⁷⁸ Policy Integrity identifies planning efforts that have used more than four scenarios to illustrate that best practice counsels against reducing the number of required Long-Term Scenarios.¹¹⁷⁹ Northwest and Intermountain state that, depending upon the size and characteristics of the transmission planning region, additional scenarios may be necessary to identify the transmission facilities that are most likely to ensure just and

US DOE Initial Comments at 14; Vermont Electric and Vermont Transco Initial Comments at 2.

¹¹⁷² GridLab Initial Comments at 12; R Street Initial Comments at 6.

¹¹⁷³ PJM Initial Comments at 74.

¹¹⁷⁴ SEIA Initial Comments at 11.

¹¹⁷⁵ AEE Reply Comments at 18.

¹¹⁷⁶ New York TOs Initial Comments at 2.

¹¹⁷⁷ Nevada Commission Initial Comments at 8–9.

¹¹⁷⁸ Policy Integrity Initial Comments at 14–16.

¹¹⁷⁹ *Id.* at 15 (citing US DOE et al., Presentation on National Transmission Planning Study at the Modeling Subcommittee Meeting, at slide 21 (June 7, 2022), <https://perma.cc/MEJ5-9JE6> (study will use approximately 100 scenarios); ERCOT, Report On Existing and Potential Electric System Constrains and Needs 10 (Dec. 2020), <https://perma.cc/JGS4-9VH7> (ERCOT has previously used five scenarios); Mohamed Labib Awad et al., *Using Market Simulations for Economic Assessment of Transmission Upgrades: Application of the California ISO Approach, in Restructured Electric Power Systems: Analysis Of Electricity Markets With Equilibrium Models* 241, 255 (Xiao-Ping Zhang ed. 2010) (economists evaluating CAISO have used seventeen scenarios)).

reasonable rates.¹¹⁸⁰ LADWP states that while developing more than four scenarios will likely be prudent in some instances such as special studies, four scenarios should be adequate for most Long-Term Regional Transmission Planning given the 20-year planning horizon and uncertainties.¹¹⁸¹

543. Some commenters stress the importance of considering multiple Long-Term Scenarios and the uncertainty associated with future conditions.¹¹⁸² ACORE suggests that uncertainties in data can be addressed with multiple Long-Term Scenarios that are continuously revised instead of granting flexibility or encouraging discounting of certain factors.¹¹⁸³ ENGIE states that a single base-case scenario is not effective at capturing trends in the resource mix and demand.¹¹⁸⁴ New York Commission and NYSEDA state that Long-Term Scenarios should reflect a range of plausible long-term futures that are relevant to the state (or transmission planning region) and should account for the uncertainty associated with looking out over longer time horizons.¹¹⁸⁵ On the other hand, R Street posits that whether scenario planning sufficiently captures information on the resource mix and demand depends more on the quality of inputs and scenario construction elements than the total number of scenarios.¹¹⁸⁶

544. Some commenters generally support requiring Long-Term Scenarios¹¹⁸⁷ including scenarios examining the effects of high energy demand,¹¹⁸⁸ and penetration of renewable resources.¹¹⁸⁹

545. Other commenters do not oppose this requirement.¹¹⁹⁰

¹¹⁸⁰ Northwest and Intermountain Initial Comments at 12.

¹¹⁸¹ LADWP Initial Comments at 4.

¹¹⁸² ACORE Initial Comments at 10; ENGIE Initial Comments at 3–4; New York Commission and NYSEDA Initial Comments at 8; R Street Initial Comments at 6.

¹¹⁸³ ACORE Initial Comments at 10.

¹¹⁸⁴ ENGIE Initial Comments at 4.

¹¹⁸⁵ New York Commission and NYSEDA Initial Comments at 8.

¹¹⁸⁶ R Street Initial Comments at 6.

¹¹⁸⁷ Breakthrough Energy Supplemental Comments at 1; Clean Energy Associations Initial Comments at 11–12; Cross Sector Representatives Supplemental Comments at 1; PJM Initial Comments at 6, 71–72; RMI Supplemental Comments at 2; US Climate Alliance Initial Comments at 2; Western PIOs Initial Comments at 29.

¹¹⁸⁸ ACORE Supplemental Comments at 1; Environmental Groups Supplemental Comments at 2.

¹¹⁸⁹ ACORE Supplemental Comments at 1; Environmental Groups Supplemental Comments at 2.

¹¹⁹⁰ Clean Energy Buyers Initial Comments at 17; Dominion Initial Comments at 25; Pine Gate Initial

546. Some commenters support requiring transmission providers to establish Long-Term Scenarios, but would modify the NOPR proposal to require a lower minimum number. AEP, Entergy, NRECA, Pine Gate, and Western PIOs support requiring at least three Long-Term Scenarios.¹¹⁹¹ CAISO argues that the Commission should not require transmission providers to develop a minimum of four Long-Term Scenarios because there is no evidence, rationale, or justification for why four is the appropriate number of scenarios to develop.¹¹⁹² Instead, CAISO asserts that the Commission should grant transmission planners the flexibility to determine the minimum number of Long-Term Scenarios that are appropriate given the specific circumstances in their region and planning cycle. However, CAISO states that if Commission were to adopt a minimum number of Long-Term Scenarios, three Long-Term Scenarios is appropriate because it allows for a base case scenario and two sensitivity scenarios.¹¹⁹³ Entergy and NRECA claim that three Long-Term Scenarios would better balance the burden with the benefit of developing an additional scenario.¹¹⁹⁴ Pine Gate recommends that, instead of requiring a fourth scenario, the Commission should permit transmission providers in each transmission planning region to develop and use no less than three Long-Term Scenarios, and then to conduct either a fourth scenario or a sensitivity analysis on the most likely Long-Term Scenario to “account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low frequency events” as proposed in the NOPR.¹¹⁹⁵

547. National Grid argues that there is an inherent trade-off between the number of Long-Term Scenarios, the quality of the data underpinning the assessment, and the frequency of reassessments. National Grid concludes that a transmission provider should not be required to plan for a scenario that is impossible or not supported by its stakeholders solely to meet the requirement that four distinct Long-Term Scenarios be developed and

Comments at 26; Utah Division of Public Utilities Initial Comments at 5.

¹¹⁹¹ AEP Initial Comments at 5, 8, 12; Entergy Initial Comments at 13; NRECA Initial Comments 35; Pine Gate Initial Comments at 26–27; Western PIOs Initial Comments at 33.

¹¹⁹² CAISO Initial Comments at 23–24.

¹¹⁹³ *Id.* at 25–26.

¹¹⁹⁴ Entergy Initial Comments at 13; NRECA Initial Comments 35.

¹¹⁹⁵ Pine Gate Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at P 124).

studied.¹¹⁹⁶ Xcel supports the use of scenarios but states that the proposed requirement to use at least four Long-Term Scenarios is too prescriptive.¹¹⁹⁷ Relatedly, LADWP states that developing more than four Long-Term Scenarios may be prudent in some instances but that it would be inefficient and a waste of resources to require all transmission providers in each transmission planning region to do so.¹¹⁹⁸

548. Some commenters broadly oppose the NOPR proposal to require transmission providers in each transmission planning region to develop at least a minimum number or specific number of Long-Term Scenarios.¹¹⁹⁹ California Commission argues that the NOPR’s approach would interfere with regional transmission planning processes, such as CAISO’s, that are closely coordinated with state resource planning and load forecasting and already effectively identify transmission necessary to accommodate changes in the resource mix and demand.¹²⁰⁰ Duke argues that requiring a minimum number of Long-Term Scenarios, while also requiring one capture high-impact, low-frequency events, places greater importance on developing scenarios purely to satisfy the requirement than on gaining consensus about what scenarios are in fact plausible or most likely.¹²⁰¹ MISO states that a prescriptive number of Long-Term Scenarios with specific factors included may introduce a level of granularity and complexity into Long-Term Regional Transmission Planning that impedes progress.¹²⁰²

549. Some commenters request that the Commission provide transmission providers in each transmission planning region with the flexibility to determine how many Long-Term Scenarios to develop.¹²⁰³ US DOE supports a

¹¹⁹⁶ National Grid Initial Comments at 14–15.

¹¹⁹⁷ Xcel Initial Comments at 10.

¹¹⁹⁸ LADWP Initial Comments at 4.

¹¹⁹⁹ California Commission Initial Comments at 21–24; Duke Initial Comments at 15; Indicated PJM TOs Initial Comments at 9–10; ISO-NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9; MISO Initial Comments at 20; NESCOE Initial Comments at 30; OMS Initial Comments at 5; PG&E Initial Comments at 6–7; SPP Initial Comments at 9–10; State Agencies Initial Comments at 14.

¹²⁰⁰ California Commission Initial Comments at 23.

¹²⁰¹ Duke Initial Comments at 15.

¹²⁰² MISO Initial Comments at 20.

¹²⁰³ Ameren Initial Comments at 13–14; Avangrid Initial Comments at 9–10; CAISO Initial Comments at 25; California Energy Commission Initial Comments at 2; Clean Energy Associations Initial Comments at 11–12; Dominion Initial Comments at 25; Entergy Initial Comments at 13; MISO Initial

Continued

requirement to identify four scenarios as a reasonable lower bound, and supports the analysis of additional scenarios, including sensitivities, but asserts that the development of Long-Term Scenarios should not be prescriptive but, rather, the Commission should provide guidelines and give transmission planning regions flexibility to work within those guidelines to capture reasonable sets of scenarios.¹²⁰⁴

550. Some commenters propose that, if the Commission does not require a minimum number of Long-Term Scenarios, the Commission should instead require that transmission providers in each transmission planning region demonstrate, on compliance, why their proposed number of Long-Term Scenarios is appropriate.¹²⁰⁵ Duke asserts that the Commission should direct transmission providers to offer on compliance a process for Long-Term Scenario development that will capture enough sufficiently plausible scenarios with distinct sets of assumptions to adequately capture a consensus view of the most likely future state(s) to occur.¹²⁰⁶

551. Other commenters call for the Commission to permit discretion on how transmission providers determine the number of Long-Term Scenarios to use.¹²⁰⁷ ISO-NE and ISO/RTO Council argue that the number of Long-Term Scenarios is an implementation detail that each transmission planning region should decide.¹²⁰⁸ NYISO states that the final order should permit each transmission planning region to conduct Long-Term Regional Transmission Planning using multiple Long-Term Scenarios that account for varying levels of achievement of local laws and regulations.¹²⁰⁹

552. MISO opposes requiring transmission providers to evaluate a specific number of Long-Term Scenarios and proposes, instead, that the Commission require that future scenarios be developed and implemented for purposes of long-term

regional transmission planning, leaving each transmission planning region to determine what and how many scenarios are appropriate. According to MISO, this approach would ensure consistency across the transmission planning regions in what is required while allowing for any needed variation within each region.¹²¹⁰ Additionally, MISO notes that it developed the futures that it uses in its Long-Range Transmission Plan through extensive stakeholder processes and that these futures reflect the specific realities of its member utilities. MISO contends that allowing transmission providers to develop the number of Long-Term Scenarios they need, and at intervals appropriate for them, encourages stakeholder buy-in and more efficient allocation of planning resources.¹²¹¹

553. California Municipal Utilities disagree with comments that urge prescriptive uniformity, arguing that uniformity involves high costs and lacks consumer protection measures against speculative transmission projects.¹²¹² For example, California Municipal Utilities argue against the proposal from Western PIOs for the development of three common scenarios to be synchronized across the Western Interconnection because this proposal amounts to central resource planning, which is not consistent with the existing process in which state and local choices drive the planning process.¹²¹³

554. Louisiana Commission states that the Commission's proposal is overly prescriptive and that the Commission should provide for a more flexible approach that allows transmission providers, retail regulators, and other stakeholders to develop scenarios with appropriate, realistic, and reasonable assumptions. Louisiana Commission states that Long-Term Scenarios should be based on reasonable ranges of assumptions for load, and generation type and location. Louisiana Commission argues that the number of scenarios required is far less important than the quality of the data and assumptions used to develop them.¹²¹⁴ MISO TOs agree that the NOPR proposal is overly prescriptive, stating that the Commission should not create unnecessary obstacles, but rather create a rule broad enough to incorporate existing processes.¹²¹⁵

555. Some commenters emphasize the need for an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to provide timely and meaningful input into which Long-Term Scenarios are developed.¹²¹⁶ For example, California Commission, NRECA, Concerned Scientists, and US Climate Alliance support the NOPR proposal to require transmission providers to disclose—subject to any applicable confidentiality protections—information and data inputs that they use to create each Long-Term Scenario.¹²¹⁷ ELCON states that the Commission should require each transmission provider to post all methodologies and inputs used in determining Long-Term Scenarios and factors to its OASIS.¹²¹⁸ NRG claims that the NOPR proposes a central determination of particular actions based on collectively determined assumptions, which gives up a major advantage of competition—the requirement that market participants take an individual view based on available information of the future viability of any investment they might make.¹²¹⁹

556. NESCOE argues that states must play a central role in Long-Term Regional Transmission Planning. Specifically, NESCOE agrees with ISO-NE, which calls for the Commission to explicitly authorize states to have a central decision-making role at all aspects of Long-Term Regional Transmission Planning, including “scenario analysis development,” to ensure necessary additional investment for a reliable, clean energy future.¹²²⁰ Similarly, Nebraska Commission adds that state regulatory commissions should have a significant role in defining Long-Term Scenarios.¹²²¹

557. AEE requests that the Commission clarify the role of states in providing input to the development of Long-Term Scenarios.¹²²²

558. GridLab states that the Commission should be prepared to act

Comments at 16, 20; MISO TOs Initial Comments at 16–17; National Grid Initial Comments at 14; Nebraska Commission Initial Comments at 5; PG&E Initial Comments at 7; PJM Initial Comments at 72; SPP Initial Comments at 9; US DOE Initial Comments at 14; Xcel Initial Comments at 10.

¹²⁰⁴ US DOE Initial Comments at 14.

¹²⁰⁵ CAISO Initial Comments at 25; Duke Initial Comments at 15; Eversource Initial Comments at 17–18; NESCOE Initial Comments at 30–31.

¹²⁰⁶ Duke Initial Comments at 15.

¹²⁰⁷ Indicated PJM TOs Initial Comments at 9–10; ISO-NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9; MISO Initial Comments at 20; NESCOE Initial Comments at 30–31; OMS Initial Comments at 5.

¹²⁰⁸ ISO-NE Initial Comments at 28; ISO/RTO Council Initial Comments at 9.

¹²⁰⁹ NYISO Initial Comments at 23.

¹²¹⁰ MISO Initial Comments at 16, 20.

¹²¹¹ MISO Reply Comments at 9–10.

¹²¹² California Municipal Utilities Reply Comments at 5.

¹²¹³ *Id.* (citing Western PIOs Initial Comments at 32–33).

¹²¹⁴ Louisiana Commission Reply Comments at 6–7.

¹²¹⁵ MISO TOs Reply Comments at 13.

¹²¹⁶ California Commission Initial Comments at 25; Clean Energy Associations Initial Comments at 12; DC and MD Offices of People's Counsel Initial Comments at 14; ELCON Initial Comments at 12; NRECA Initial Comments at 35; Pacific Northwest State Agencies at 14–15; US Climate Alliance Initial Comments at 2.

¹²¹⁷ California Commission Initial Comments at 25; NRECA Initial Comments at 35; Concerned Scientists Reply Comments at 15–16; US Climate Alliance Initial Comments at 2.

¹²¹⁸ ELCON Initial Comments at 12.

¹²¹⁹ NRG Initial Comments at 8.

¹²²⁰ NESCOE Reply Comments at 2 (citing ISO-NE Initial Comments at 2–4).

¹²²¹ Nebraska Commission Initial Comments at 5–6.

¹²²² AEE Initial Comments at 19.

as the arbiter of stakeholder concerns about Long-Term Scenario design, similar to the role that state public utility commissions play in the integrated resource planning process, and that this may require new staff, resources, and the development of new expertise at the Commission.¹²²³

c. Commission Determination

559. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to develop at least three distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning. In implementing this requirement, transmission providers must develop, at least once during the five-year Long-Term Regional Transmission Planning cycle, at least three distinct Long-Term Scenarios that, at a minimum, incorporate the seven categories of factors listed in the Categories of Factors section above. We find that requiring transmission providers to develop at least three distinct Long-Term Scenarios as part of Long-Term Regional Transmission Planning strikes the appropriate balance between establishing a sufficient number of Long-Term Scenarios and the associated burden of developing and using Long-Term Scenarios in Long-Term Regional Transmission Planning. We also find that requiring transmission providers to develop at least three distinct Long-Term Scenarios instead of four, as proposed in the NOPR, is more consistent with the manner in which some transmission providers currently employ scenarios in their existing regional transmission planning process.¹²²⁴ We also reiterate, as stated in the NOPR, that if transmission providers produce a base-case Long-Term Scenario in Long-Term Regional Transmission Planning, that base case should be consistent with what the transmission provider determines is the most likely scenario to occur.¹²²⁵

560. In addition, we adopt the NOPR proposal to require, consistent with

Order No. 890's transparency transmission planning principle, transmission providers in each transmission planning region to publicly disclose (subject to any applicable confidentiality protections) information and data inputs that they use to create each Long-Term Scenario.¹²²⁶ We also adopt the NOPR proposal to require transmission providers in each transmission planning region, consistent with Order No. 890's coordination transmission planning principle, to provide stakeholders an opportunity to provide timely and meaningful input into how Long-Term Scenarios are developed.¹²²⁷ Consistent with Order No. 890 and Order No. 1000's coordination transmission planning principle, we require transmission providers, with the input of their customers and other stakeholders, to craft coordination requirements that work for those transmission providers and their customers and other stakeholders. Furthermore, we adopt the NOPR proposal to require transmission providers to revise the regional transmission planning process in their OATTs to outline an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios. We conclude that these requirements will help ensure that transmission providers will have the necessary information to identify Long-Term Transmission Needs and identify, evaluate, and select Long-Term Regional Transmission Facilities to address those needs. Furthermore, by requiring transmission providers to afford stakeholders a meaningful opportunity

to propose future outcomes that are probable, we believe that this requirement helps to ensure that Long-Term Transmission Needs are being addressed in a more efficient or cost-effective manner.¹²²⁸

561. We also note the important role of states in developing Long-Term Scenarios. As the Commission stated in Order No. 890 and Order No. 1000, and we reiterate here, our expectation is that "all transmission providers will respect states' concerns" when engaging in the regional transmission planning process.¹²²⁹ We strongly encourage states to participate actively in the development of Long-Term Scenarios, as well as in all other aspects of Long-Term Regional Transmission Planning. In response to NESCOE's and AEE's concerns about the role of state regulators in the development of Long-Term Scenarios and their use in Long-Term Regional Transmission Planning,¹²³⁰ we find that, consistent with Order No. 890,¹²³¹ transmission planning must be coordinated with interested stakeholders, including relevant state regulators that wish to participate in the Long-Term Regional Transmission Planning process. As reflected throughout this final order, we recognize that states have a particularly important role to play in the development of Long-Term Regional Transmission Facilities and encourage transmission providers to work with states in a way that reflects that role in addition to complying with the relevant requirements established herein.

562. In response to commenters that argue that the Commission should require four or more Long-Term Scenarios,¹²³² we affirm that nothing in this final order precludes or prevents transmission providers from proposing

¹²²⁸ Order No. 1000, 136 FERC ¶ 61,051 at P 150.

¹²²⁹ *Id.* P 212; Order No. 890, 118 FERC ¶ 61,119 at P 574.

¹²³⁰ AEE Initial Comments at 8; NESCOE Reply Comments at 2 (citing ISO-NE Initial Comments at 2–4).

¹²³¹ Order No. 890, 118 FERC ¶ 61,119 at P 574.

¹²³² ACORE Initial Comments at 10; Advanced Energy Buyers Initial Comments at 8; AEE Initial Comments at 8; APPA Initial Comments at 29; Arizona Commission Initial Comments at 6; Concerned Scientists Reply Comments at 18–19; ELCON Initial Comments at 12; ENGIE Initial Comments at 4; Evergreen Action Initial Comments at 3; Georgia Commission Initial Comments at 4–5; GridLab Initial Comments at 12; ITC Initial Comments at 12; Nevada Commission Initial Comments at 8–9; New England for Offshore Wind Initial Comments at 2; NextEra Initial Comments at 65; Northwest and Intermountain Initial Comments at 12; NYISO Initial Comments at 25; Ørsted Initial Comments at 7; Southeast PIOs Initial Comments at 46; SPP Market Monitor Initial Comments at 7; US Chamber of Commerce Initial Comments at 7; US DOE Initial Comments at 14–15; Vermont Electric and Vermont Transco Initial Comments at 2.

¹²²³ GridLab Initial Comments at 11–12.

¹²²⁴ *See, e.g.*, CAISO Initial Comments at 26 (explaining that "CAISO typically has utilized three scenarios in its public policy planning process, a base case scenario and two sensitivity scenarios"); Entergy Initial Comments at 13–14 (explaining that MISO currently uses three scenarios in its transmission planning process and arguing that the use of three scenarios enables "transmission providers to 'bookend' plausible outcomes to plan no-regrets additions to meet the grid, and then develop a scenario between those two to better inform the decision making"); NRECA Initial Comments at 35 n.100 (highlighting that MISO uses three scenarios in its transmission planning process).

¹²²⁵ NOPR, 179 FERC ¶ 61,028 at P 123.

¹²²⁶ The transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

¹²²⁷ The coordination transmission planning principle requires transmission providers to provide customers and other stakeholders with the opportunity to participate fully in the transmission planning process. The transmission planning process must provide for the timely and meaningful input and participation of customers and other stakeholders regarding the development of transmission plans, allowing customers and other stakeholders to participate in the early stages of development. Order No. 890, 118 FERC ¶ 61,119 at P 454.

to use more than three Long-Term Scenarios in Long-Term Regional Transmission Planning. To the extent that transmission providers, in consultation with stakeholders, conclude that using more than three Long-Term Scenarios is appropriate for Long-Term Regional Transmission Planning in their transmission planning region, those transmission providers may propose to use more than three Long-Term Scenarios in their compliance filings.

563. In response to California Commission's comments about the interaction between the development of Long-Term Scenarios and existing regional transmission planning processes,¹²³³ we believe the final order, as modified from the NOPR proposal, addresses this concern and provides transmission providers with sufficient flexibility to tailor the development of Long-Term Scenarios to their transmission planning regions' specific needs or existing practices, as discussed elsewhere in this final order.¹²³⁴

5. Types of Long-Term Scenarios

a. NOPR Proposal

564. In the NOPR, the Commission proposed to require that each Long-Term Scenario incorporate, at a minimum, the categories of factors listed in the requirement above. As discussed in the Factors section of the NOPR,¹²³⁵ the Commission proposed that each Long-Term Scenario must be consistent with Federal, state, and local laws and regulations that affect the future resource mix; Federal, state, and local laws and regulations on decarbonization and electrification; and state-approved integrated resource plans. However, the Commission explained that each Long-Term Scenario may vary according to assumptions about the remaining categories of factors described in the NOPR, as well as with respect to other characteristics of the future electric power system. The Commission explained that it neither proposed to require the development of a specific Long-Term Scenario or specific set of Long-Term Scenarios, nor did it propose to require that transmission providers identify the relative likelihood of different Long-Term Scenarios except where transmission providers develop a base

case scenario, as described more fully below.¹²³⁶

565. The Commission proposed to require transmission providers in each transmission planning region to develop a plausible and diverse set of Long-Term Scenarios.¹²³⁷ The Commission explained that the set of at least four Long-Term Scenarios must be: (1) plausible, that is they must reasonably capture probable future outcomes, and (2) diverse in the sense that transmission providers must be able to distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each scenario. The Commission proposed to require that if the transmission providers in a transmission planning region use a base case scenario, that scenario should be consistent with the scenario that the transmission providers determine to be the most likely scenario to occur.

b. Comments

566. Some commenters support the Commission's proposal to require transmission providers in each transmission planning region to develop a plausible and diverse set of Long-Term Scenarios.¹²³⁸ For example, GridLab agrees that the Commission should require that transmission providers demonstrate that their Long-Term Scenarios capture a reasonable range of possible futures. GridLab argues that scenarios that are too conservative will lead to similar load-resource and transmission portfolio scenarios, which limits the value of scenario planning in managing uncertainty and risk.¹²³⁹ Illinois Commission argues that the NOPR's proposed requirement for diverse and plausible scenarios is important, and that Long-Term Scenarios must consider a wide array of conditions.¹²⁴⁰

567. Some commenters discuss the need for certain types of Long-Term Scenarios.¹²⁴¹ Certain TDUs and PIOs

argue that, although Long-Term Scenarios should include anticipated levels of generation, they should also include "book end" scenarios of high- and low-load growth.¹²⁴² Clean Energy Associations argue that, because the Inflation Reduction Act provides for significant funding for electrification, at least some scenarios should evaluate transmission needs under higher-than-anticipated load growth.¹²⁴³

568. PJM describes four scenarios that it might use: (1) a low uncertainty scenario with known inputs, such as legislative and regulatory laws and announced deactivations and load forecasts; (2) a medium uncertainty scenario that includes state and local goals and economic retirement analysis; (3) a higher uncertainty scenario that adds more speculative and aspirational goals; and (4) a high-impact-low-frequency resilience evaluation scenario that includes low-probability, high-impact events. PJM states that the scenarios should be: (1) based on a clearly defined, robust set of factor development criteria grounded in customer needs; (2) capable of adapting to an evolving set of future system conditions; and (3) crafted to produce the appropriate level of transmission.¹²⁴⁴

569. Western PIOs state that one scenario should be based on existing policy and assumptions about generation retirements and electrification that are likely to occur. Western PIOs state that a second scenario would build on that base case scenario by assuming Public Policy Requirements and utility and corporate goals are met or exceeded, as well as high levels of electrification and generation retirements. Western PIOs state that a third scenario should address high-impact, low-frequency extreme weather events. Western PIOs state that the fourth scenario could be reserved for a scenario unique to each of the non-RTO/ISO transmission planning regions.¹²⁴⁵

570. ACORE argues that uncertainties in data do not require granting

Energy Associations Initial Comments at 10–11; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 18–19; Georgia Commission Initial Comments at 4–5; NESCOE Initial Comments at 32; NextEra Initial Comments at 65; PIOs Initial Comments at 22–23; PJM Initial Comments at 73–74; US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 15; Utah Division of Public Utilities Initial Comments at 5–6; Western PIOs Initial Comments at 33.

¹²⁴² Certain TDUs Initial Comments at 18; PIOs Initial Comments at 22–23.

¹²⁴³ Clean Energy Associations Initial Comments at 11 (citing Inflation Reduction Act, Public Law 117–169 (2022)).

¹²⁴⁴ PJM Initial Comments at 73–74.

¹²⁴⁵ Western PIOs Initial Comments at 33.

¹²³³ California Commission Initial Comments at 23.

¹²³⁴ See *supra* Categories of Factors, Requirement to Incorporate Categories of Factors section; Categories of Factors, Stakeholder Process and Transparency section.

¹²³⁵ NOPR, 179 FERC ¶ 61,028 at PP 104–112.

¹²³⁶ *Id.* P 121.

¹²³⁷ The Commission noted that different assumptions about the factors and data inputs used to develop Long-Term Scenarios and other characteristics of the future electric power system determine whether the set of Long-Term Scenarios are plausible and diverse.

¹²³⁸ APPA Initial Comments at 29; Clean Energy Buyers Initial Comments at 17; DC and MD Offices of People's Counsel Initial Comments at 13; GridLab Initial Comments at 11 & n.12; Illinois Commission Initial Comments at 7; Mississippi Commission Reply Comments at 9; NARUC Initial Comments at 10; NESCOE Initial Comments at 32; New York Commission and NYSEDA Initial Comments at 8; SPP Market Monitor Initial Comments at 7.

¹²³⁹ GridLab Initial Comments at 11.

¹²⁴⁰ Illinois Commission Initial Comments at 7.

¹²⁴¹ ACORE Initial Comments at 10–11; AEE Initial Comments at 8; APPA Initial Comments at 29; Certain TDUs Initial Comments at 18; Clean

flexibility or encouraging discounting, but instead can be addressed with multiple scenarios that are continuously revised as recommended in the NOPR. For example, one Long-Term Scenario can include a discounted set of goals, while another can add contingency factors for when demand exceeds those goals; and a range of scenarios could be incorporated for the extent of electrification of buildings and transportation. ACORE states that scenario analysis should incorporate a probabilistic-based range of future weather and extreme events which, ACORE asserts, will support the analyses of the benefits of mitigation of those extreme events and system contingencies and mitigation of weather and load uncertainty.¹²⁴⁶

571. AEE recommends that the Commission require Long-Term Scenarios that consider anticipated distributed energy resource deployments.¹²⁴⁷ Evergreen Action urges the Commission to require that at least one Long-Term Scenario contemplate a 100% clean-energy grid by 2035, to reflect the Biden Administration's target of 100% carbon-free electricity by 2035.¹²⁴⁸ Similarly, NextEra argues that the Commission should require that one of the Long-Term Scenarios be based on an economy-wide, net-zero emissions scenario or at least a Federal net-zero emissions mandate limited to the power sector.¹²⁴⁹ In contrast, Utah Division of Public Utilities states that one of the Long-Term Scenarios should consider little or no state renewable energy or decarbonization goals or requirements to assist in determining transmission costs for states that have less onerous goals.¹²⁵⁰

572. APPA requests that one of the Long-Term Scenarios represent a base case of business as usual.¹²⁵¹ Eversource supports the NOPR proposal to use the "most likely scenario to occur" as the base case for analysis of Long-Term Scenarios.¹²⁵² Georgia Commission argues that a base case scenario should reflect the expected long-term mix of generating capacity, with additional scenarios reflecting alternative carbon emission constraints, fuel prices, and growth in distributed energy resources.¹²⁵³ US Climate Alliance

states that business-as-usual cases should be consistent with state and Federal policy and used in addition to alternative scenarios that demonstrate a range of factors influencing the changing grid.¹²⁵⁴

573. However, PIOs state that the Commission should not use the phrase "business as usual" as it is misleading in a rapidly changing electric industry.¹²⁵⁵ US DOE argues against identifying the likelihood of any one Long-Term Scenario, including a base case scenario, because identifying a single such scenario as most likely is challenging and discourages the analysis of more scenarios and sensitivities, undermining the value of scenario analysis. Instead, US DOE argues that transmission facilities that provide high value in multiple scenarios should be identified as more likely to provide value to the future transmission system, because expansion options that provide high value in many future scenarios are flexible, and that flexibility to accommodate multiple future scenarios is more important than trying to characterize the likelihood of any one scenario.¹²⁵⁶

574. Senator Schumer supports requiring a high variable energy resource penetration scenario.¹²⁵⁷

c. Commission Determination

575. We adopt the NOPR proposal to require transmission providers in each transmission planning region to develop a plausible and diverse set of at least three Long-Term Scenarios. Specifically, we find that the set of at least three Long-Term Scenarios must be: (1) plausible, meaning that each scenario must itself be reasonably probable, and collectively that the set of plausible scenarios must reasonably capture probable future outcomes, and (2) diverse, in the sense that transmission providers can distinguish distinct transmission facilities or distinct benefits of similar transmission facilities in each Long-Term Scenario. We find that requiring Long-Term Scenarios to be both plausible and diverse prevents the development of Long-Term Scenarios that may otherwise be too conservative, speculative, or similar for transmission providers to identify Long-Term Transmission Needs and identify, evaluate, and select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address those needs. Absent a requirement that

Long-Term Scenarios be both plausible and diverse, transmission providers could develop Long-Term Scenarios in a manner that undercuts one of the primary benefits of using scenario-based planning practices, which is to help ensure that transmission providers can account for the uncertainty about future conditions when conducting Long-Term Regional Transmission Planning.

576. Moreover, we also require that each *individual* Long-Term Scenario be plausible (*i.e.*, individually the scenario must be reasonably probable) because, absent such a requirement, we are concerned that the set of Long-Term Scenarios may include a Long-Term Scenario that rests on assumptions about the factors and data inputs that do not reasonably capture possible future outcomes. Additionally, we also clarify the term "diverse" to mean that the *set* of Long-Term Scenarios must represent a reasonable range of probable future outcomes consistent with the requirement for plausibility, based on assumptions about the factors and data inputs.

577. We disagree with commenters that argue that the Commission should modify the NOPR proposal and prescribe specific types of Long-Term Scenarios for transmission providers to use in Long-Term Regional Transmission Planning.¹²⁵⁸ We are not persuaded that we should require transmission providers to develop either a specific Long-Term Scenario or a specific set of Long-Term Scenarios because we believe that transmission providers, with an opportunity for timely and meaningful input from stakeholders, are in the best position to determine which plausible Long-Term Scenarios are applicable to their transmission planning region. Further, we do not find it necessary to require transmission providers to develop low-, medium-, and high-level assumptions for the factors that transmission providers believe to be important except where transmission providers develop a base case scenario, as discussed above.¹²⁵⁹

¹²⁵⁸ ACORE Initial Comments at 10–11; AEE Initial Comments at 8; APPA Initial Comments at 29; Certain TDUs Initial Comments at 18, 22; Clean Energy Associations Initial Comments at 11; Evergreen Action Initial Comments at 3; Eversource Initial Comments at 19; Georgia Commission Initial Comments at 4–5; NESCOE Initial Comments at 32; NextEra Initial Comments at 65; PIOs Initial Comments at 22–23; PJM Initial Comments at 73–74; US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 15; Utah Division of Public Utilities Initial Comments at 5–6; Western PIOs Initial Comments at 33.

¹²⁵⁹ See *supra* Types of Long-Term Scenarios section.

¹²⁴⁶ ACORE Initial Comments at 10–11.

¹²⁴⁷ AEE Initial Comments at 8.

¹²⁴⁸ Evergreen Action Initial Comments at 3.

¹²⁴⁹ NextEra Initial Comments at 65.

¹²⁵⁰ Utah Division of Public Utilities Initial Comments at 5–6.

¹²⁵¹ APPA Initial Comments at 29.

¹²⁵² Eversource Initial Comments at 19.

¹²⁵³ Georgia Commission Initial Comments at 4–5.

¹²⁵⁴ US Climate Alliance Initial Comments at 2.

¹²⁵⁵ PIOs Initial Comments at 22.

¹²⁵⁶ US DOE Initial Comments at 15.

¹²⁵⁷ Senator Schumer Supplemental Comments at 2.

6. Sensitivities for High-Impact, Low-Frequency Events

a. NOPR Proposal

578. In the NOPR, the Commission proposed to require that at least one of the four distinct Long-Term Scenarios that transmission providers in each transmission planning region use in Long-Term Regional Transmission Planning account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events. The Commission proposed to allow transmission providers the flexibility to determine which high-impact, low-frequency event should be modeled in this Long-Term Scenario as part of Long-Term Regional Transmission Planning based on the Commission's understanding that each transmission planning region may see a need to evaluate a different type of high-impact, low-frequency event. The Commission stated that high-impact, low-frequency events may include extreme weather events or events associated with potential cyber-attacks. The Commission explained that this Long-Term Scenario accounting for a high-impact, low-frequency event can be developed, for example, by assuming greater-than-expected electricity demand and greater-than-expected generation or transmission outages. The Commission proposed that the use of either probabilistic transmission planning¹²⁶⁰ or stochastic techniques would be sufficient to satisfy this requirement, but it did not propose to require either approach at this time.¹²⁶¹

579. The Commission noted that transmission providers can develop sensitivities for every Long-Term Scenario to assess how outcomes modeled in Long-Term Scenarios may depend on an assumption about electric power system model inputs that does not vary across scenarios (e.g., higher natural gas prices). The Commission explained that such sensitivities can provide valuable information about the need for and benefits of potential transmission facilities, but also noted

that they can be burdensome to develop if applied to every scenario.¹²⁶²

b. Comments

580. Some commenters support the NOPR proposal to require one Long-Term Scenario to account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events as part of Long-Term Regional Transmission Planning.¹²⁶³ Ameren states that the inclusion of such events in Long-Term Regional Transmission Planning would provide additional information for transmission providers, stakeholders, state regulators, and others to consider when determining the need for regional transmission facilities.¹²⁶⁴ According to Arizona Commission, including such a scenario, and giving the transmission provider the discretion to determine what this should be for its region, may provide the added benefit of allowing state involvement in identifying the appropriate "high-impact" event to be analyzed. Arizona Commission additionally asserts that the Commission should require transmission providers to develop sensitivities for each Long-Term Scenario to better understand the range of benefits under each scenario.¹²⁶⁵

581. Eversource supports the NOPR proposal given the increasing threat of extreme weather events and potential cyber-attacks.¹²⁶⁶ Similarly, Illinois Commission states that the inclusion of high-impact, low-frequency events in the transmission planning process is reasonable and should include cyber-security attacks and extreme weather events to strengthen the system's resilience.¹²⁶⁷ New England for Offshore Wind argues that it is prudent for the Commission to require transmission providers to develop at least one high-impact, low-frequency scenario due to the increased likelihood of extreme weather events due to climate change.¹²⁶⁸ SoCal Edison states that incorporating probabilistic assumptions

about extreme weather in Long-Term Scenarios would be a reasonable, proactive approach to mitigate the impacts of extreme weather when it occurs.¹²⁶⁹

582. Likewise, Cypress Creek, City of New Orleans Council, DC and MD Offices of People's Counsel, and PIOs support the inclusion of extreme weather events in Long-Term Scenarios.¹²⁷⁰ Business Council for Sustainable Energy contends that Long-Term Scenarios must account for the increase in significant climate events, acknowledging that the most salient events to assess may vary regionally.¹²⁷¹ US DOE asserts that regional transmission planning should consider the effects of extreme events, including extreme weather events, on the availability and reliability of the transmission system.¹²⁷² WE ACT comments that requiring transmission providers to consider extreme weather events in Long-Term Regional Transmission Planning is a positive step towards addressing grid reliability in the face of more frequent and intensifying weather events brought on by the climate crisis.¹²⁷³

583. Other commenters express more general support for the study of high-impact, low-frequency events in Long-Term Regional Transmission Planning.¹²⁷⁴ Clean Energy Associations emphasize that no scenario or sensitivity should assume that historical operating conditions will persist given the unpredictable and increasing impact of climate change.¹²⁷⁵ Grid United states that high-impact, low-frequency scenarios should not be considered "black swan" events since they occur on a regular, but low-frequency, basis. Moreover, Grid United asks that the Commission define or provide examples of high-impact, low-frequency events that transmission providers could incorporate into Long-Term Scenarios to

¹²⁶⁹ SoCal Edison Initial Comments at 12.

¹²⁷⁰ City of New Orleans Council Initial Comments at 8; Cypress Creek Reply Comments at 5–6; DC and MD Offices of People's Counsel Reply Comments at 6; PIOs Reply Comments at 10; *see also* RMI Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 2–3.

¹²⁷¹ Business Council for Sustainable Energy Initial Comments at 4.

¹²⁷² US DOE Initial Comments at 5.

¹²⁷³ WE ACT Initial Comments at 2.

¹²⁷⁴ *See* Business Council for Sustainable Energy Initial Comments at 4; Clean Energy Associations Initial Comments at 12; Evergreen Action Initial Comments at 3–4; Grid United Initial Comments at 4–5; NARUC Initial Comments at 11–12; NASUCA Initial Comments at 4–5; NESCOE Initial Comments at 32–33; NRECA Initial Comments at 35–36; Pattern Energy Initial Comments at 25; SoCal Edison Initial Comments at 12.

¹²⁷⁵ Clean Energy Associations Initial Comments at 12.

¹²⁶² *Id.* P. 125.

¹²⁶³ Ameren Initial Comments at 13; Arizona Commission Initial Comments at 6; California Commission Initial Comments at 24; Evergreen Action Initial Comments at 4; Eversource Initial Comments at 18; Grid United Initial Comments at 4; New England for Offshore Wind Initial Comments at 2; Pacific Northwest State Agencies Initial Comments at 14; US DOE Initial Comments at 15.

¹²⁶⁴ Ameren Initial Comments at 13–14.

¹²⁶⁵ Arizona Commission Initial Comments at 6–7.

¹²⁶⁶ Eversource Initial Comments at 18.

¹²⁶⁷ Illinois Commission Initial Comments at 6.

¹²⁶⁸ New England for Offshore Wind Initial Comments at 2.

¹²⁶⁰ NOPR, 179 FERC ¶ 61,028 at P 124. The Commission stated that it considers probabilistic transmission planning approaches to include any transmission planning approach that uses a probability distribution to assign probabilities to one or more inputs to the transmission model. The Commission stated that these inputs can include shorter-term operational inputs (like wind generation or generation outages). The Commission described stochastic techniques as including adaptive transmission planning techniques that identify transmission facilities that optimize transmission net-benefits over a time horizon under market and regulatory uncertainty about the future. *Id.* P 124 n.228.

¹²⁶¹ *Id.* P. 124.

provide clarity and consistency across transmission planning regions.¹²⁷⁶

584. NARUC does not oppose the requirement that one of the Long-Term Scenarios account for high-impact, low-frequency events but notes that states' input is important when developing such scenarios.¹²⁷⁷ Pattern Energy states that, with respect to low-probability, high-risk event scenarios, the Commission should: (1) require the North American Electric Reliability Corporation and the Regional Entities to develop the scope of low-probability, high-risk events for each region of the country and then (2) require transmission providers to model at least one of the events in a rotation of the three-year review of the 20-year plans to identify vulnerabilities that can be addressed through transmission solutions that increase resilience.¹²⁷⁸ Vermont Electric and Vermont Transco request clarity on what scenarios the Commission would consider sufficiently high-impact to be analyzed but not so high-impact as to be unable to be mitigated by effective Long-Term Regional Transmission Planning.¹²⁷⁹

585. Some commenters support the Commission's proposal to permit transmission providers to model high-impact, low-frequency events via probabilistic or stochastic methods.¹²⁸⁰ PJM states that it will sometimes use probabilistically-derived parameters and sometimes use deterministically-derived parameters in its Long-Term Scenarios, depending on which is more appropriate.¹²⁸¹ Policy Integrity asserts that the Commission should ensure the use of modeling techniques that address uncertainty, such as stochastic programming and robust optimization models.¹²⁸² Policy Integrity argues that modeling that fails to consider uncertainties that arise from various factors could reduce the cost-efficacy and efficiency of results and, ultimately, result in unjust and unreasonable rates.¹²⁸³ Policy Integrity cites the European Network of Transmission System Operators' consideration of the interactions between gas and electric systems as an example of best practices for choosing scenarios.¹²⁸⁴

586. Some commenters provided views on the Commission's proposal to require transmission providers to develop sensitivities for each Long-Term Scenario.¹²⁸⁵ Business Council for Sustainable Energy states that it is important that scenario planning cover a range of sensitivities, and that the long-term needs of the transmission system as well as long-term policy goals should be incorporated.¹²⁸⁶ NERC states that studies could more adequately study various sensitivities and extreme conditions (e.g., extreme weather) to ensure a reliable, resilient, and secure bulk power system on a longer time horizon, which could, in turn, help inform transmission expansion plans particularly related to the changing resource mix.¹²⁸⁷

587. GridLab recommends that the Commission provide a high-level requirement and guidance on what kinds of factors are more effectively considered in scenario versus sensitivity analysis and how sensitivity analysis might be used in tandem with scenario analysis.¹²⁸⁸ Policy Integrity states that, instead of mandating only a minimum number of Long-Term Scenarios, the Commission should also require sensitivity analysis of critical drivers of transmission needs.¹²⁸⁹ In addition, Policy Integrity recommends that the Commission require transmission providers to run a sensitivity for each Long-Term Scenario using a 30-year transmission planning horizon and compare the results with those from the analysis of each Long-Term Scenario using a 20-year transmission planning horizon.¹²⁹⁰ PIOs state that the Commission should specify that, if any critical variable (e.g., natural gas prices, capital costs of wind and solar, short and long duration storage, and carbon capture and sequestration) is the same in more than two Long-Term Scenarios, then transmission providers must conduct sensitivities that use different values for that variable.¹²⁹¹

588. Although NRECA does not oppose the proposal that at least one

Long-Term Scenario account for high-impact, low-frequency events from extreme weather, NRECA states that the Commission should not require any Long-Term Scenarios to account for possible cyber-attacks. NRECA asserts that modeling cyber-attacks and their effects would be extraordinarily complex and risk disclosure of non-public Critical Electric Infrastructure Information (CEII) and that such risks are better addressed in North American Electric Reliability Corporation standards development, noting that cyber-attacks may already be evaluated under North American Electric Reliability Corporation Transmission Planning Reliability Standard TPL-001-4.¹²⁹²

589. Some commenters oppose requiring one Long-Term Scenario for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events.¹²⁹³ LADWP asserts that a more meaningful measure of benefits or needs associated with high-impact, low-frequency events may be a periodic examination of the impacts of large-scale single points of failures.¹²⁹⁴ US Chamber of Commerce argues against requiring a Long-Term Scenario for high-impact, low-frequency events because, it asserts, the scope and impacts of such events on the transmission system can be infinite in number.¹²⁹⁵

590. MISO argues that, although the impacts of large-scale generation loss events associated with extreme weather events should be considered in Long-Term Regional Transmission Planning, the Commission should consider requiring analysis or sensitivities of extreme events that are focused on the times or snapshots when the system is potentially impacted by those events instead of requiring a separate extreme event scenario.¹²⁹⁶ MISO further argues that the Commission should not require a specific number or type of sensitivities, which can vary over time, but instead transmission providers should have flexibility to assess the appropriate sensitivities needed to test scenarios and results at the time those

¹²⁷⁶ Grid United Initial Comments at 5.

¹²⁷⁷ NARUC Initial Comments at 11–12.

¹²⁷⁸ Pattern Energy Initial Comments at 25.

¹²⁷⁹ Vermont Electric and Vermont Transco Initial Comments at 3.

¹²⁸⁰ California Commission Initial Comments at 24–25; Eversource Initial Comments at 18; PJM Initial Comments at 74–75.

¹²⁸¹ PJM Initial Comments at 75.

¹²⁸² Policy Integrity Initial Comments at 7.

¹²⁸³ *Id.* at 6.

¹²⁸⁴ *Id.* at 9 (citing European Commission, Key Cross Border Infrastructure Projects, <https://perma.cc/4U6X-Q2WN> (last visited Aug. 9, 2022)).

¹²⁸⁵ Business Council for Sustainable Energy Initial Comments at 4; NERC Initial Comments at 7; Exelon Initial Comments 7 & n.7; GridLab Initial Comments at 17–19; Idaho Power Initial Comments at 5; Minnesota State Entities Initial Comments at 5; NYISO Initial Comments at 26; PIOs Initial Comments at 23–24; Policy Integrity Initial Comments at 14–16; PPL Initial Comments at 9; R Street Initial Comments at 6; US DOE Initial Comments at 15–16.

¹²⁸⁶ Business Council for Sustainable Energy Initial Comments at 4.

¹²⁸⁷ NERC Initial Comments at 7.

¹²⁸⁸ GridLab Initial Comments at 17–18.

¹²⁸⁹ Policy Integrity Initial Comments at 15.

¹²⁹⁰ *Id.* at 10–11.

¹²⁹¹ PIOs Initial Comments at 23–24.

¹²⁹² NRECA Initial Comments at 35–36 (citing GDS Associates, Report, at 13 (Aug. 17, 2022); NERC Reliability Standard TPL-001-4, Table 1—Steady State, <https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf>).

¹²⁹³ LADWP Initial Comments at 3; MISO Initial Comments at 27–28, 38–39; Mississippi Commission Reply Comments at 6; OMS Initial Comments at 6; US Chamber of Commerce Initial Comments at 7.

¹²⁹⁴ LADWP Initial Comments at 3.

¹²⁹⁵ US Chamber of Commerce Initial Comments at 7.

¹²⁹⁶ MISO Initial Comments at 27–28.

are being developed.¹²⁹⁷ Similarly, OMS argues that analyzing system performance during extreme weather for all Long-Term Scenarios would result in a better understanding of the benefits of transmission and ensure reliability regardless of future changes in generation and/or load.¹²⁹⁸ PIOs likewise recommend that the Commission require that transmission providers model extreme weather events as sensitivities in each Long-Term Scenario and, specifically, that they model at least extreme heat or cold over geographic areas that are experiencing these extremes.¹²⁹⁹

591. NESCOE states that it supports the study of high-impact, low-frequency events; however, NESCOE argues that the proposal raises questions about whether codifying such a requirement blurs the line between public policy planning and reliability planning, contrary to the NOPR's contention that none of the proposals seek to alter the reliability planning process. NESCOE contends that making the study of high-impact, low-frequency events discretionary instead of mandatory under Long-Term Regional Transmission Planning would avoid such tension.¹³⁰⁰ Mississippi Commission states that the Commission should not mandate that transmission planning attempt to predict extreme weather events and over-build the system, because "predicting where the next hurricane or tornado will land is speculative." Mississippi Commission argues that a better approach is to incorporate construction standards (*e.g.*, North American Electric Reliability Corporation, IEEE, local reliability criteria) designed to withstand such events.¹³⁰¹

592. Idaho Power raises concerns that developing multiple sensitivities for multiple Long-Term Scenarios over a long-term transmission planning horizon introduces too many variables.¹³⁰² Minnesota State Entities state that defining specific methods in the final order—such as the difference between a "sensitivity" and what is included in a "scenario"—can be unnecessarily confusing and complex.¹³⁰³ US DOE encourages transmission providers to perform sensitivity analyses but states that the Commission should only require that

one Long-Term Scenario analyze high-impact, low-frequency events.¹³⁰⁴

c. Commission Determination

593. We modify the NOPR proposal to require transmission providers in each transmission planning region to develop at least one sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.¹³⁰⁵ As discussed below, we acknowledge support in the record for studying high-impact, low-frequency events as proposed in the NOPR¹³⁰⁶ but also recognize that requiring a fourth Long-Term Scenario might be a burdensome way to study such events as compared to a sensitivity.¹³⁰⁷ We find that more clearly defining the type of system conditions that transmission providers must model to account for uncertain operational outcomes—in particular, multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area—compared to the NOPR proposal, will enable transmission providers to better account for periods when regional transmission facilities may have particularly high value by decreasing the risk of loss of load and/or decreasing the cost to reliably serve load.

594. Therefore, we require that, after developing at least three Long-Term Scenarios, transmission providers develop a sensitivity for each of the Long-Term Scenarios.¹³⁰⁸ We provide transmission providers with flexibility to conduct this sensitivity either before or after identifying potential regional transmission solutions to the Long-Term

Transmission Needs identified using those Long-Term Scenarios. Conducting this sensitivity before identifying potential regional transmission solutions can be useful because it may help transmission providers to identify such solutions. On the other hand, conducting this sensitivity after identifying potential regional transmission solutions to Long-Term Transmission Needs would allow transmission providers to engage in efforts to develop additional or alternative regional transmission solutions to address such conditions.

595. In conducting this sensitivity, transmission providers change the data inputs of the underlying Long-Term Scenarios—in terms of load, generation, generator outages, and transmission outages—to account for uncertain operational outcomes that determine the benefits of or need for regional transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area, while maintaining the underlying longer-term determinants of the Long-Term Scenario (*e.g.*, the installed capacity of each generation resource). The sensitivity can be thought of as a "stress test" for all Long-Term Scenarios.

596. We find it necessary to require the consideration of a more narrowly defined set of conditions, as compared to the broader high-impact, low-frequency event conditions described in the NOPR, to include multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.¹³⁰⁹ Extreme weather events have occurred more frequently in recent years,¹³¹⁰ are periods when regional transmission facilities have particularly high value,¹³¹¹ and create system conditions that transmission providers can readily specify compared to contingencies with an unknown root cause.¹³¹² During these extreme weather

¹³⁰⁴ US DOE Initial Comments at 16.

¹³⁰⁵ The Commission proposed in the NOPR to require that at least one of four Long-Term Scenarios account for uncertain operational outcomes that determine the benefits of or need for transmission facilities during high-impact, low-frequency events. NOPR, 179 FERC ¶ 61,028 at P 124.

¹³⁰⁶ See, *e.g.*, New England for Offshore Wind Initial Comments at 2; see also Arizona Commission Initial Comments at 6–7. We also note that the Commission has previously discussed that "[e]xtreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future." Order No. 896, 183 FERC ¶ 61,191 at P 2.

¹³⁰⁷ See, *e.g.*, MISO Initial comments at 27.

¹³⁰⁸ See NOPR, 179 FERC ¶ 61,028 at P 125 n.229. A sensitivity represents a single assumption about a short-term input or factor (some input with a value that may change throughout a day or year). A scenario represents an assumption about a longer-term input or factor (*e.g.*, resource retirements and additions or public policies).

¹³⁰⁹ See, *e.g.*, Grid United Initial Comments at 4–5 (stating that "the Commission should define or provide examples of the low-frequency, high impact events that it would like to be considered for planning purposes").

¹³¹⁰ See *supra* The Overall Need for Reform section; see also NOPR, 179 FERC ¶ 61,028 at P 45; Breakthrough Energy Initial Comments at 8.

¹³¹¹ See ACEG Initial Comments at 5; PIOs Initial Comments at 21; US DOE Initial Comments at 5–6.

¹³¹² In terms of specifying the system conditions during extreme weather events, transmission providers can, for example, look at previous severe cold weather events to identify how load might increase, how load and generation forecasts might be incorrect, and how generation and transmission outages might occur during a future extreme weather event.

¹²⁹⁷ *Id.* at 39.

¹²⁹⁸ OMS Initial Comments at 6.

¹²⁹⁹ PIOs Initial Comments at 21.

¹³⁰⁰ NESCOE Initial Comments at 32–33.

¹³⁰¹ Mississippi Commission Reply Comments at 6.

¹³⁰² Idaho Power Initial Comments at 5.

¹³⁰³ Minnesota State Entities Initial Comments at 5.

events, generation and transmission outages can be widespread, occur at the same time, and persist due to a common cause like freezing temperatures or limited fuel availability. This more narrowly defined set of conditions also gives transmission providers more direct guidance on how to comply with the requirements of this final order.¹³¹³

597. Although we are only requiring that one sensitivity analysis specific to extreme weather events be applied to each Long-Term Scenario to comply with this final order, we do not preclude transmission providers from considering additional sensitivities. We recognize that transmission providers may consider several other sensitivities as important and helpful in evaluating the benefits of and need for Long-Term Regional Transmission Facilities. For example, transmission providers can develop sensitivities to account for a cyber-attack, significant forecast error, or fuel price volatility. We encourage transmission providers to assess the need to develop other sensitivities as part of Long-Term Regional Transmission Planning.

598. We find that modeling extreme weather events as sensitivities is appropriate for Long-Term Regional Transmission Planning. We first note that extreme weather events can occur under any assumed future scenario but do not, by themselves, represent changes in the way that factors are used in Long-Term Scenarios to determine Long-Term Transmission Needs.¹³¹⁴ Therefore, we believe that applying a sensitivity to each Long-Term Scenario is a more accurate way to evaluate the effects of high-impact, low-frequency events than considering such events in a distinct Long-Term Scenario. Second, although there is a burden associated with conducting sensitivities, the overall burden of conducting a sensitivity analysis is comparatively lower than that of developing a new, separate Long-Term Scenario. This is because sensitivities will be conducted using the existing Long-Term Scenarios, where most inputs, and the factors and assumptions used to develop the scenarios, have already been established and mapped. Adjusting a set of existing inputs to test the impact of the changes on a Long-Term Scenario through a sensitivity analysis is therefore less burdensome than developing an entirely new Long-Term Scenario.

599. In addition, we highlight that transmission providers can use the

required sensitivity analyses to evaluate the need for, or benefits of, increased Interregional Transfer Capability provided by candidate Long-Term Regional Transmission Facilities. We recognize that certain Long-Term Regional Transmission Facilities could increase Interregional Transfer Capability by changing the topology of the transmission system, even if the specific transmission facility is not directly connected to a neighboring transmission planning region's transmission system. We believe that an increase in Interregional Transfer Capability could provide significant benefits during extreme weather events that result in multiple concurrent and sustained generation and/or transmission outages.¹³¹⁵ We note that several commenters discuss the need for greater Interregional Transfer Capability because of extreme weather events¹³¹⁶ and the importance of modeling extreme weather event conditions to capture the benefits of regional transmission facilities.¹³¹⁷ As discussed in the Evaluation of the Benefits of Regional Transmission Facilities section below, we require transmission providers to consider increased Interregional Transfer Capability provided by a Long-Term Regional Transmission Facility when measuring Benefit 6.¹³¹⁸ We believe that transmission providers can evaluate Benefit 6, including reduced loss of load and reduced production costs during extreme weather events that result in multiple concurrent and sustained generation and/or transmission outages, using this required sensitivity, among other sensitivities that transmission providers may develop to capture extreme events and system contingencies.

600. We disagree with NESCOE's concern that a requirement to study the impact of high-impact, low-frequency events might "blur[] the line between public policy planning and reliability planning."¹³¹⁹ Rather, as discussed below in the Evaluation of the Benefits of Regional Transmission Facilities

section, we believe that the requirement complements Benefit 6 (Mitigation of Extreme Weather Events and Unexpected System Conditions) given the high probability that extreme weather events will cause unplanned transmission outages and the likelihood that such events will continue to occur at regular intervals.¹³²⁰ Although this final order requires a more comprehensive consideration of benefits, it does not alter Order No. 1000's requirements for transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the transmission planning region's reliability and economic requirements.

601. We also acknowledge LADWP's concern that a more meaningful measure of benefits or needs associated with high-impact, low-frequency events may be a periodic examination of the impacts of large-scale single point failure.¹³²¹ Although we do not preclude transmission providers from conducting such a study, such a study would not meet the final order's requirement to conduct a sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.

7. Specificity of Data Inputs

a. NOPR Proposal

602. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to use "best available data inputs" when developing Long-Term Scenarios.¹³²² The Commission stated that, by "best available," the Commission did not imply that there is a single "best" value for each data input that transmission providers must use, but rather that best practices are used to develop that data input.¹³²³

603. The Commission proposed to define "best available data inputs" as data inputs that are timely and developed using diverse and expert perspectives, adopted via a process that satisfies the Order Nos. 890 and 1000 transparency transmission planning principles described above, and reflect

¹³¹⁵ See, e.g., Order No. 896, 183 FERC ¶ 61,191 at PP 85–88.

¹³¹⁶ BP Initial Comments at 10; Breakthrough Energy Initial Comments at 2; Kansas Commission Initial Comments at 8–9; NARUC Initial Comments at 23; US DOE Initial Comments at 39–42; see also ELCON Initial Comments at 8 (arguing Interregional Transfer Capability should be a driver of transmission needs); PJM Initial Comments at 66–67.

¹³¹⁷ See ACEG Initial Comments at 5; PIOs Initial Comments at 21; US DOE Initial Comments at 5–6.

¹³¹⁸ See *infra* Evaluation of the Benefits of Regional Transmission Facilities, Required Benefits, Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions section.

¹³¹⁹ NESCOE Initial Comments at 33.

¹³²⁰ See *infra* Evaluation of the Benefits of Regional Transmission Facilities, Required Benefits, Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions section.

¹³²¹ LADWP Initial Comments at 3.

¹³²² NOPR, 179 FERC ¶ 61,028 at PP 130–134.

¹³²³ *Id.* P 130.

¹³¹³ See, e.g., Grid United Initial Comments at 4–5.

¹³¹⁴ See MISO Initial Comments at 27–28; OMS Initial Comments at 6.

the list of factors that transmission providers must incorporate into Long-Term Scenarios.¹³²⁴ The Commission explained that an example of data inputs that could meet this requirement are the long-term load forecasts of demand that RTOs/ISOs currently use for predicting long-term resource adequacy. The Commission stated that another example of data inputs that could meet this requirement are the most recent data on renewable energy potential and distributed energy resources developed by national labs.¹³²⁵

604. The Commission proposed to require transmission providers in each transmission planning region to update all data inputs each time they reassess and revise, as necessary, their Long-Term Scenarios, which, as explained in the NOPR, the Commission proposed to require that they do at least every three years. As indicated in the Long-Term Regional Transmission Planning section of the NOPR,¹³²⁶ the Commission also proposed to require that the Order Nos. 890 and 1000 transmission planning principles apply to the process through which transmission providers determine which data inputs to use in their Long-Term Scenarios. For example, consistent with the coordination transmission planning principle established in Order No. 890, the Commission proposed to require that transmission providers in each transmission planning region give stakeholders the opportunity to provide timely and meaningful input concerning which data inputs to use in Long-Term Scenarios.¹³²⁷

605. The Commission preliminarily found that a requirement to use the best available data inputs was necessary to ensure that transmission providers are regularly updating data inputs and then using timely and accurate data inputs to inform Long-Term Scenarios. The Commission stated that data inputs can drive the results of Long-Term Regional Transmission Planning. As a result, the Commission explained that data inputs can directly affect which transmission facilities may be selected and, in turn, Commission-jurisdictional rates.¹³²⁸

b. Comments

i. Interest in Best Available Data Requirement

606. Many commenters generally support the NOPR proposal for “best available data,” but some recommend that the Commission monitor data

inputs.¹³²⁹ AEE states that it is not practical to make a more prescriptive requirement for data inputs than the NOPR proposal and recommends that the Commission be vigilant in monitoring data inputs.¹³³⁰ Policy Integrity states that the NOPR proposal is crucial in protecting against strategic modeling behavior.¹³³¹ WATT Coalition adds that “best available data” on future generation must be used because demand and energy profiles are inherently uncertain.¹³³²

607. ACEG claims that the FPA supports the Commission’s proposed requirement to plan based on the best available data, noting that section 217(b)(4) requires the Commission to exercise its authority “in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligation of load-serving entities.”¹³³³ ACEG argues that load-serving entities’ service obligations will be more accurately predicted by the best available forecasting methodologies.¹³³⁴

608. Clean Energy Buyers state that it is important to get stakeholder input on data inputs, as has been done through MISO’s Long-Range Transmission Planning effort.¹³³⁵ Breakthrough Energy states that Long-Term Scenarios should use “best available data.”¹³³⁶

ii. Reservations with the Best Available Data Requirement

609. Several commenters support the NOPR proposal but nevertheless have suggestions about how to modify the proposal.¹³³⁷ For example, several commenters request that the

Commission create a common dataset, publish a database of best available sources of data, or otherwise standardize data inputs.¹³³⁸ Southeast PIOs state that the Commission should publish a regularly updated database of best available data sources and require transmission providers to justify any decision not to use that database, arguing that flexibility in project selection can only work if the selection process utilizes reliable and standardized inputs.¹³³⁹ SEIA urges the Commission to issue standards or guidelines that define what constitutes “best available data inputs” for each of the seven categories of factors.¹³⁴⁰ R Street contends that intraregional standardization could support internal consistency and transparency and focus scarce stakeholder capital.¹³⁴¹

610. ELCON notes that, as part of the three-year reassessment of Long-Term Scenarios, the Commission may decide that identifying or standardizing data inputs and sources may help to ensure that transmission providers are consistently using timely and widely accepted data.¹³⁴² Interwest endorses US DOE’s proposal in its comments to the ANOPR to standardize data inputs.¹³⁴³ ACORE states that an identification of certain common data sets and modeling best practices will reduce uncertainty, improve transparency, and achieve greater consistency among transmission planning regions.¹³⁴⁴

611. ENGIE states that data inputs should be sourced from Federal and state agencies whenever possible.¹³⁴⁵ Renewable Northwest states that determining a future resource mix for NorthernGrid is possible with publicly available data.¹³⁴⁶ GridLab states that the Commission should consider whether to require that transmission providers either use unadjusted, publicly available data in Long-Term Regional Transmission Planning or justify why using proprietary data would provide superior results.

612. Several commenters state that it is not necessary for the Commission to facilitate the development of data or

¹³²⁹ AEE Initial Comments at 23; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17–18; DC and MD Offices of People’s Counsel Initial Comments at 14; Duke Initial Comments at 16–17; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ITC Initial Comments at 12; NARUC Initial Comments at 13–15; NRECA Initial Comments at 35–36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13–14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 6; US DOE Initial Comments at 16–17; WATT Coalition Initial Comments at 7.

¹³³⁰ AEE Initial Comments at 23.

¹³³¹ Policy Integrity Initial Comments at 17.

¹³³² WATT Coalition Initial Comments at 7.

¹³³³ ACEG Initial Comments at 26–27 (citing 16 U.S.C. 824q(b)(4)).

¹³³⁴ *Id.* at 27.

¹³³⁵ Clean Energy Buyers Initial Comments at 18.

¹³³⁶ Breakthrough Energy Supplemental Comments at 1.

¹³³⁷ ACEG Initial Comments at 7; ACORE Initial Comments at 8–9; Eversource Initial Comments at 20–21; GridLab Initial Comments at 23; OMS Initial Comments at 5; Pine Gate Initial Comments at 27–29; PIOs Initial Comments at 19–20; Policy Integrity Initial Comments at 6, 16–18; Southeast PIOs Initial Comments at 47–48.

¹³³⁸ ACEG Initial Comments at 7; ACORE Initial Comments at 8–9; GridLab Initial Comments at 23; PIOs Initial Comments at 19–20; Southeast PIOs Initial Comments at 47–48.

¹³³⁹ Southeast PIOs Initial Comments at 47.

¹³⁴⁰ SEIA Initial Comments at 11; SEIA Reply Comments at 4.

¹³⁴¹ R Street Initial Comments at 7.

¹³⁴² ELCON Initial Comments at 13.

¹³⁴³ Interwest Initial Comments at 8 (citing US DOE ANOPR Initial Comments at 12–15).

¹³⁴⁴ ACORE Reply Comments at 5.

¹³⁴⁵ ENGIE Initial Comments at 3.

¹³⁴⁶ Renewable Northwest Initial Comments at 17.

¹³²⁴ *Id.* P 131.

¹³²⁵ *Id.* P 131 n.247.

¹³²⁶ *Id.* PP 64–67.

¹³²⁷ *Id.* P 132.

¹³²⁸ *Id.* P 133.

standardize inputs.¹³⁴⁷ PPL, for example, asserts that the task of developing data inputs should be left to transmission providers, with the caveat that the entire process should avoid hindsight bias or an inappropriate shift in burden or responsibility to the transmission provider.¹³⁴⁸ SPP states that the development of data inputs facilitated by the Commission could provide value if implemented in a way that does not create additional burden to the assessment. SPP suggests that allowing access to recommended data sources or standard information would provide an additional reference for transmission providers to validate their own data, incorporate portions of the data, or utilize all of the data, as appropriate.¹³⁴⁹

613. US Climate Alliance and US DOE support transparency requirements for data inputs.¹³⁵⁰ Similarly, California Commission and NRECA support transparency requirements for data inputs, subject to appropriate confidentiality considerations.¹³⁵¹ Colorado Consumer Advocate contends that greater transparency and opportunities for meaningful stakeholder input regarding data inputs for Long-Term Regional Transmission Planning will improve the regional transmission planning process and help to ensure that Order No. 890 transmission planning principles are met.¹³⁵²

614. Concerned Scientists state that the final order should require transmission providers and load-serving entities to submit to the relevant transmission planner an account of planned investments and retirements over the transmission planning horizon because not doing so ensures a transmission planning process that is less informed than it can and should be. Concerned Scientists state that excluding these minimum requirements from the final order will inevitably lead to the exclusion of information needed by regulators, stakeholders, and the transmission providers themselves to make informed investment decisions.¹³⁵³ PJM, which supports the

NOPR proposal, states that, while it is important to consider resource retirements when developing planning assumptions, generation retirement forecasts may be interpreted by stakeholders as sending economic signals concerning the viability of existing generating units. Thus, PJM urges the Commission to provide clear direction on how to balance the heightened transparency and public processes proposed in the NOPR with appropriate safeguards against releasing data that could preempt unit owner economic decisions, as well as decisions by market participants.¹³⁵⁴

615. ITC, PJM, and SEIA support the NOPR proposal, and ITC and SEIA agree with PJM's suggestion that the Commission hold regular forums, workshops, or technical conferences to determine best practices in developing best available data.¹³⁵⁵

616. SPP Market Monitor contends that the Commission should further provide guidance in the form of parameters by which transmission providers should define the phrase "best available data," which SPP Market Monitor argues would aid in ensuring that the Long-Term Scenarios studied and transmission projects or facilities planned are consistent and reasonable.¹³⁵⁶ Relatedly, Pine Gate states that the NOPR's failure to address source accuracy in the definition of best available data inputs may introduce subjectivity into Long-Term Regional Transmission Planning, obscure sources, and inhibit the ability of stakeholders to meaningfully engage in the Long-Term Regional Transmission Planning process. To remedy these concerns, Pine Gate suggests that the Commission define "best available data inputs" as data inputs that: (1) are current and developed using diverse and expert perspectives expressed during a stakeholder process; (2) have identified sources; (3) are adopted via a process that satisfies Order No. 890's transparency planning principle; and (4) reflect the list of factors that transmission providers must incorporate into Long-Term Scenarios.¹³⁵⁷ Policy Integrity states that the Commission should require external vetting of data inputs used by a party without a stake in the outcomes.¹³⁵⁸

617. Several commenters state that the final order should add a requirement

that data must be accurate.¹³⁵⁹ ELCON notes that utilities should consider whether a data source's historical projections ultimately proved to be accurate when identifying "best available" inputs, and Vermont Electric and Vermont Transco agree.¹³⁶⁰ Arizona Commission supports the use of relevant, timely, and accurate data.¹³⁶¹

618. LADWP asserts that the determination of "best available data" should be changed to "the most accurate data inputs available" at the time of study because "best" is subjective but "most accurate" is clear and objective. LADWP states that, if data is interpreted differently, as may be the case under the "best available" standard, then results will be inconsistent. For example, LADWP states that the "most accurate data inputs available" for load inputs for near-term planning and for data for generation and energy storage capacities would be data derived from projections based on actual field measurements, and from in-service equipment (instead of from manufacturing brochures or articles), respectively. LADWP states that for new technologies, the projected availability and performance parameters should be based on actual data when possible. For example, LADWP states that data derived from field operating experience with prototypes should be considered "most accurate" as compared to lab test data. LADWP contends that transmission providers should be careful not to take "expert perspectives" at face value, but should seek to use data inputs that show a strong correlation to scientifically verifiable facts. Furthermore, LADWP states, projected data based on administrative law or executed interconnection agreements should be considered more certain, and hence more accurate, than data based on corporate or government goals.¹³⁶²

619. GridLab recommends that the Commission request that the national laboratories and other public agencies work with transmission providers, resource developers, and others to evaluate the historical accuracy of publicly available data sources.¹³⁶³ However, Ameren sees no reason to expand the definition of best available data inputs to include an evaluation of data source entities' historical accuracy identifying and projecting trends

¹³⁴⁷ Ameren Initial Comments at 14–15; Idaho Power Initial Comments at 5; NESCOE Initial Comments at 35–36; New York State Department Initial Comments at 8–9; PPL Initial Comments at 10.

¹³⁴⁸ PPL Initial Comments at 10.

¹³⁴⁹ SPP Initial Comments at 11–12.

¹³⁵⁰ US Climate Alliance Initial Comments at 2; US DOE Initial Comments at 17.

¹³⁵¹ California Commission Initial Comments at 25; NRECA Initial Comments at 35–37 (citing GDS Associates, Report, at 13 (Aug. 17, 2022)).

¹³⁵² Colorado Consumer Advocate Initial Comments at 26.

¹³⁵³ Concerned Scientists Reply Comments at 17.

¹³⁵⁴ PJM Reply Comments at 22.

¹³⁵⁵ ITC Initial Comments at 12; PJM Initial Comments at 76–77; SEIA Initial Comments at 11; SEIA Reply Comments at 4–5.

¹³⁵⁶ SPP Market Monitor Initial Comments at 8.

¹³⁵⁷ Pine Gate Initial Comments at 28.

¹³⁵⁸ Policy Integrity Initial Comments at 17–18.

¹³⁵⁹ ELCON Initial Comments at 13; LADWP Initial Comments at 4; Vermont Electric and Vermont Transco Initial Comments at 3.

¹³⁶⁰ ELCON Initial Comments at 13; Vermont Electric and Vermont Transco Initial Comments at 3.

¹³⁶¹ Arizona Commission Initial Comments at 7.

¹³⁶² LADWP Initial Comments at 4.

¹³⁶³ GridLab Initial Comments at 24.

because the open and transparent planning process of diverse stakeholders will identify any questionable or non-reliable data sources.¹³⁶⁴

620. ELCON states that the Commission may need to clarify what data is considered “timely” and argues, for example, that the Commission should not establish a mandate in favor of using historical data (e.g., actual data from the previous 12 months) because such data may not reflect current and future operational needs.¹³⁶⁵ Pine Gate is concerned that the use of the term “timely” in the definition of “best available data inputs” may lead to confusion and inconsistency amongst transmission providers.¹³⁶⁶

621. PJM Market Monitor states that both aggregate and very specific locational data on future demand and the future resource mix will be critical for efficient and cost-effective transmission planning.¹³⁶⁷

iii. Concerns With Best Available Data

622. Several commenters either oppose the NOPR proposal or object to specific aspects of the NOPR proposal.¹³⁶⁸ Ameren, EEI, and PPL state that the NOPR proposal is unnecessary and too prescriptive.¹³⁶⁹ Idaho Commission agrees that it is too prescriptive.¹³⁷⁰ EEI states that, while using the best available data inputs when preparing the Long-Term Scenarios is appropriate, a *pro forma* definition may not be necessary.¹³⁷¹

623. PPL expresses concern that the proposed requirement for data inputs will unnecessarily burden transmission providers by effectively shifting a burden from data owners (who are in the best position to control and ensure data accuracy) to the transmission provider and instead recommends that the Commission strengthen the requirements applicable to the data owners or data source entities.¹³⁷² Dominion states that using best

available data inputs should not be a requirement because transmission providers should be permitted to select the data inputs that are most appropriate for their own situation, as they know their transmission systems best. Dominion additionally does not support defining “best available data inputs” as proposed because it would limit transmission providers’ flexibility to conduct transmission planning that is most appropriate to their unique system needs.¹³⁷³

624. MISO, Utah Division of Public Utilities, and Xcel state that the NOPR proposal on data inputs is a potential source of conflict.¹³⁷⁴ MISO is concerned that parties opposing particular long-range transmission planning outcomes could seize on the proposed language and argue that some other data was the best available data, thereby delaying the process; and the resulting disputes could potentially slow down the transmission planning process and ultimately delay much needed transmission.¹³⁷⁵ Xcel agrees.¹³⁷⁶ Utah Division of Public Utilities attests that requiring transmission providers to use the best data available is not based on evidence showing that data inputs currently used by transmission providers have led to unjust or discriminatory rates, and may produce unnecessary and time-consuming disagreements among stakeholders regarding which data inputs to use.¹³⁷⁷ National Grid asserts that the term “best available” data is vague and subjective, which introduces development, regulatory and implementation inefficiencies.¹³⁷⁸ Clean Energy Associations argue that transmission providers should be required to explain the number and the basis for including each input they choose to include.¹³⁷⁹

iv. Flexibility Issues

625. Several commenters, some that support the NOPR proposal and some that do not, call for flexibility in allowing transmission providers to determine what constitutes best available data. ISO–NE and NYISO support the NOPR proposal but request that the Commission provide transmission providers with some

flexibility about how to satisfy this requirement.¹³⁸⁰ ISO–NE asserts that the Commission should allow flexibility for ISO–NE to rely on the states to determine the data inputs, with its technical support and stakeholder input, and NESCOE, which opposes the NOPR proposal, agrees.¹³⁸¹ NESCOE is concerned about the prescriptive nature of the NOPR proposal and contends that data inputs should be determined on a region-by-region basis by transmission providers with input from states and stakeholders.¹³⁸² MISO agrees on both points.¹³⁸³ Duke, which generally supports the NOPR proposal to define best available data inputs and requirement to follow a transparent process to develop the data inputs, states that because there is not a single “best” value for each input, the emphasis should be on best practices to develop the data inputs, which should be left to the regions to develop with their specific stakeholders.¹³⁸⁴

626. In addition, NYISO requests that the Commission revise the definition of best available data to permit flexibility on how it reflects factors considered in the scenarios. Specifically, NYISO requests that the language in the NOPR specifying that the data inputs must “reflect the list of factors that transmission providers must incorporate into Long-Term Scenarios” should be modified to “reflect the factors that the transmission provider considers in the scenarios” to reflect the authority of transmission planning regions to identify which factors should be used in Long-Term Scenarios. NYISO adds that transmission providers should have authority over how to interpolate and employ their data sets.¹³⁸⁵

627. MISO, which opposes the NOPR proposal, contends that the Commission should allow transmission providers to determine, in consultation with its stakeholders, what data is most appropriate, but require transmission providers to use the most up-to-date data from the source that they select.¹³⁸⁶ MISO recommends that, if the final order includes the NOPR proposal for best available data, then the Commission should clarify that transmission providers may satisfy the requirement by using the most up-to-date data that they have selected and that reflects practical limitations

¹³⁶⁴ Ameren Initial Comments at 15.

¹³⁶⁵ ELCON Initial Comments at 13.

¹³⁶⁶ Pine Gate Initial Comments at 28.

¹³⁶⁷ PJM Market Monitor Initial Comments at 4.

¹³⁶⁸ Ameren Initial Comments at 14–15;

Dominion Initial Comments at 26–28; EEI Initial Comments at 14; ELCON Initial Comments at 13; Idaho Power Initial Comments at 5; LADWP Initial Comments at 4; MISO Initial Comments at 40–41; MISO TOs Initial Comments at 18–19; National Grid Initial Comments at 14; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 35–36; PPL Initial Comments at 9–10; R Street Initial Comments at 7; Vermont Electric and Vermont Transco Initial Comments at 3; Xcel Initial Comments at 10.

¹³⁶⁹ Ameren Initial Comments at 14–15; EEI Initial Comments at 14; PPL Initial Comments at 9.

¹³⁷⁰ Idaho Commission Initial Comments at 3.

¹³⁷¹ EEI Initial Comments at 14.

¹³⁷² PPL Initial Comments at 9–10.

¹³⁷³ Dominion Initial Comments at 26–27.

¹³⁷⁴ MISO Initial Comments at 29; Utah Division of Public Utilities Initial Comments at 6; Xcel Initial Comments at 10.

¹³⁷⁵ MISO Initial Comments at 40.

¹³⁷⁶ Xcel Initial Comments at 10.

¹³⁷⁷ Utah Division of Public Utilities Initial Comments at 6.

¹³⁷⁸ National Grid Initial Comments at 14.

¹³⁷⁹ Clean Energy Associations Initial Comments at 13.

¹³⁸⁰ ISO–NE Initial Comments at 28; NYISO Initial Comments at 28.

¹³⁸¹ ISO–NE Initial Comments at 28; NESCOE Initial Comments at 35–36.

¹³⁸² NESCOE Initial Comments at 36.

¹³⁸³ MISO Initial Comments at 40.

¹³⁸⁴ Duke Initial Comments at 16–17.

¹³⁸⁵ NYISO Initial Comments at 28.

¹³⁸⁶ MISO Initial Comments at 40.

regarding the precision and scope of the data.¹³⁸⁷ MISO TOs suggest that the Commission consider articulating principles and guidelines and let transmission planning regions develop their own conception of “best available data” in the interest of flexibility.¹³⁸⁸ Nevada Commission states that the definition of “best available data” may need further comment and will likely evolve as the Long-Term Regional Transmission Planning process is implemented.¹³⁸⁹

628. National Grid requests that the Commission clarify that transmission providers have final and sole responsibility and discretion to determine what is “best available data” as transmission providers are best situated to make these determinations in consultation with their stakeholders. National Grid also seeks clarity from the Commission as to what “diverse” means as it describes best available data inputs. National Grid further asserts that the Commission should distinguish between Long-Term Scenarios based on diverse inputs in each scenario.¹³⁹⁰

v. Best Sources of Data Issues

629. Several commenters, some that support the NOPR proposal and some that do not, make suggestions about the best sources of data. Several commenters state that transmission providers already have the best available data.¹³⁹¹ Nebraska Commission further states that the current methods used by RTOs/ISOs would meet the NOPR’s proposed requirements.¹³⁹² PPL states that transmission providers already use a “best available data inputs” standard in transmission planning but must rely on other entities’ data.¹³⁹³ EEI states that, if the Commission adopts a definition for best available data, it should acknowledge that transmission providers and load-serving entities often may possess this data.¹³⁹⁴

630. Several commenters state that load-serving entities have the best available data.¹³⁹⁵ Eversource recommends that the Commission require the RTOs/ISOs to collaborate with the transmission owners regarding transmission owners’ forecast of load

localized peak times.¹³⁹⁶ PIOs state that the Commission should require load-serving entities to provide their generation and load forecasts to transmission providers so that they have reasonable information to use and do not have to perform their own estimates.¹³⁹⁷ ACEG and Clean Energy Associations agree.¹³⁹⁸

631. Western PIOs state that the Western Electricity Coordinating Council databases on load and generation forecasts and the Western Electricity Coordinating Council Anchor dataset constitute best available data.¹³⁹⁹ NARUC argues that any reasonable, credible source of data should be allowed to supplement more traditional sources like the national laboratories and RTO/ISO-generated data.¹⁴⁰⁰ SREA recommends that, to the extent possible, the Commission should recognize the National Renewable Energy Lab’s Annual Technology Baseline (NREL ATB) as the Nation’s preferred data set.¹⁴⁰¹ Policy Integrity states that the Commission should urge transmission providers to engage independent researchers in the process to ensure inclusion of the latest modeling and computational developments.¹⁴⁰² PIOs state that the Commission could publish a regularly updated list of databases that meet the “best available data requirement,” such as the following current databases: NREL ATB data, US DOE’s Annual Energy Outlook for fuel costs, and NREL’s Electrification Futures Study for electrification trends. PIOs suggests that the Commission could additionally partner with the US DOE and National Laboratories to develop appropriate databases.¹⁴⁰³

632. Entergy asserts that integrated resource plans approved by retail commissions should be considered the best available data, and Louisiana Commission and Mississippi Commission agree.¹⁴⁰⁴ However, Kentucky Commission Chair Chandler disagrees with the propositions that local data provided by a utility in an integrated resource plan is superior to other data and that RTOs/ISOs should be required to rely on such data.¹⁴⁰⁵

c. Commission Determination

633. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to use “best available data inputs” when developing Long-Term Scenarios. As the Commission explained in the NOPR, by “best available,” we do not imply that there is a single “best” value for each data input that transmission providers must use, but rather that best practices will be used to develop each data input. We adopt, with modification, the NOPR proposal to define “best available data inputs” as data inputs that are timely, developed using best practices and diverse and expert perspectives,¹⁴⁰⁶ and adopted via a process that satisfies the transmission planning principles of Order Nos. 890 and 1000.¹⁴⁰⁷ We further adopt the NOPR proposal to require that best available data inputs also reflect the list of factors that transmission providers account for in their Long-Term Scenarios.¹⁴⁰⁸ By “reflect the list of factors,” we mean the data inputs that correspond to the list of factors that transmission providers have determined might affect Long-Term Transmission Needs.¹⁴⁰⁹ We also adopt the NOPR proposal to require transmission providers to update, as necessary, all data inputs each time they reassess and revise their Long-Term Scenarios.

634. Finally, in addition, we adopt the NOPR proposal to require that the Order Nos. 890 and 1000 transmission planning principles apply to the process

¹⁴⁰⁶ While we largely adopt the definition of “best available data inputs” proposed in the NOPR, we modify it to reflect the requirement that “best available data inputs” are developed using best practices.

¹⁴⁰⁷ For example, the transparency transmission planning principle requires transmission providers to reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans. Transmission providers must make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies. Order No. 890, 118 FERC ¶ 61,119 at P 471. Order No. 1000 applied this and other Order No. 890 transmission planning principles to regional transmission planning processes. Order No. 1000, 136 FERC ¶ 61,051 at P 151.

¹⁴⁰⁸ One example of a data input dataset that would meet the requirement for best available data are the long-term load forecasts of demand that RTOs/ISOs currently use for predicting long-term resource adequacy. Another example of a data input dataset that would meet the requirement for best available data is the most recent data on renewable energy potential and distributed energy resources developed by national labs.

¹⁴⁰⁹ For example, a transmission provider might determine that corporate goals for corporations less than \$20 million are too small to affect Long-Term Transmission Needs and not include these corporate goals in its Long-Term Scenarios. This transmission provider does not have any obligation to develop data inputs corresponding to these omitted corporate goals.

¹³⁸⁷ *Id.* at 29.

¹³⁸⁸ MISO TOs Initial Comments at 19.

¹³⁸⁹ Nevada Commission Initial Comments at 9.

¹³⁹⁰ National Grid Initial Comments at 14.

¹³⁹¹ EEI Initial Comments at 14; Nebraska Commission Initial Comments at 6; PJM Initial Comments at 76; PPL Initial Comments at 9–10.

¹³⁹² Nebraska Commission Initial Comments at 6.

¹³⁹³ PPL Initial Comments at 9–10.

¹³⁹⁴ EEI Initial Comments at 14.

¹³⁹⁵ *Id.*; Eversource Initial Comments at 20; Xcel Initial Comments at 10.

¹³⁹⁶ Eversource Initial Comments at 20.

¹³⁹⁷ PIOs Initial Comments at 19.

¹³⁹⁸ ACEG Reply Comments at 23; Clean Energy Associations Reply Comments at 7.

¹³⁹⁹ Western PIOs Initial Comments at 31.

¹⁴⁰⁰ NARUC Initial Comments at 13.

¹⁴⁰¹ SREA Reply Comments at 26.

¹⁴⁰² Policy Integrity Initial Comments at 17.

¹⁴⁰³ PIOs Initial Comments at 19.

¹⁴⁰⁴ Entergy Initial Comments at 18; Louisiana Commission Reply Comments at 7; Mississippi Commission Reply Comments at 9.

¹⁴⁰⁵ Kentucky Commission Chair Chandler Reply Comments at 3.

through which transmission providers determine which data inputs to use in their Long-Term Scenarios. Consistent with the coordination transmission planning principle established in Order No. 890, we also adopt the NOPR proposal to require transmission providers in each transmission planning region to give stakeholders an opportunity to provide timely and meaningful input during each Long-Term Regional Transmission Planning cycle concerning which data inputs to use in Long-Term Scenarios.¹⁴¹⁰ Also, we clarify that the right to challenge data inputs via dispute resolution as discussed in Order No. 890 is available for interested parties with respect to data inputs that transmission providers develop for Long-Term Regional Transmission Planning.¹⁴¹¹

635. We agree, in part, with NYISO's suggestion to revise the wording of the NOPR proposal that required best available data to reflect "the list of factors that transmission providers must incorporate into Long-Term Scenarios."¹⁴¹² NYISO states that the NOPR language should be modified to "reflect the factors that the public utility transmission provider considers in the scenarios."¹⁴¹³ As discussed in the Categories of Factors section of this final order, we explain that transmission providers need not account for a factor, stakeholder-identified or otherwise, if they determine that factor is unlikely to affect Long-Term Transmission Needs. We find that transmission providers must use best available data when determining whether each factor is likely to affect Long-Term Transmission Needs. Once transmission providers have determined that a factor is likely to affect Long-Term Transmission Needs, they must use the best available data when they then account for that factor in the development of Long-Term Scenarios.

636. We find that a requirement to use the best available data inputs is warranted to ensure that transmission providers are regularly updating data inputs and using timely and accurate data inputs to inform Long-Term Scenarios. We further find that data inputs can drive the results of Long-Term Regional Transmission Planning. As a result, we find that data inputs affect transmission providers' ability to identify Long-Term Transmission Needs and thus affect the ability to identify,

evaluate, and select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address those needs. We note that many commenters share this view and support the NOPR proposal.¹⁴¹⁴

637. We disagree with commenters asserting that the requirements for data inputs would be overly burdensome to transmission providers.¹⁴¹⁵ We believe that, because most transmission providers already endeavor to use best available data inputs to ensure credible results in regional transmission planning, this final order's requirements for data inputs will not impose an unreasonable burden beyond existing practices today. Further, as many commenters note,¹⁴¹⁶ any increase in transmission providers' burden from such requirements is outweighed by the benefits of establishing reasonable safeguards for accuracy and confidence in Long-Term Regional Transmission Planning.

638. We disagree with commenters' arguments that the final order requirements for data inputs would lead to problems because stakeholders will delay Long-Term Regional Transmission Planning by contesting the data used by transmission providers.¹⁴¹⁷ Similarly, we disagree with commenters' arguments that the requirements for data inputs unnecessarily limit transmission providers' flexibility in producing data

inputs.¹⁴¹⁸ As discussed above, this final order establishes requirements for data inputs used in Long-Term Scenarios and requires that stakeholders have an opportunity to provide timely and meaningful input during each Long-Term Regional Transmission Planning cycle concerning those data inputs. However, transmission providers have significant flexibility about which data inputs they use in Long-Term Scenarios, and no commenters have provided us with convincing or specific arguments that stakeholder input will undermine that flexibility or cause consequential delays to the Long-Term Regional Transmission Planning process.

639. We decline to adopt the suggestion of commenters to standardize data inputs used by transmission providers in Long-Term Regional Transmission Planning.¹⁴¹⁹ Imposing further requirements to enforce uniformity in data is challenging given regional variation in transmission planning approaches. Further, it might stifle innovation that would improve Long-Term Regional Transmission Planning.

640. We decline to adopt the modifications of the NOPR proposal suggested by certain commenters to establish specific accuracy standards in addition to requiring that transmission providers use best available data inputs.¹⁴²⁰ While we agree that transmission providers should strive for data accuracy, including by assessing the historical accuracy of different data sources where appropriate, a specific accuracy standard would be difficult to develop and administer given the diversity of different data inputs.¹⁴²¹ As we explain above, transmission providers must use best available data inputs, which include forecasted data, and must develop such inputs using diverse and expert perspectives. They must use best practices to develop data inputs, and must do so in an open and transparent stakeholder process. Taken together, we believe that these

¹⁴¹⁴ ACORE Initial Comments at 8; AEE Initial Comments at 22; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17–18; DC and MD Offices of People's Counsel Initial Comments at 14; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ISO–NE Initial Comments at 28; ITC Initial Comments at 12; Mississippi Commission Initial Comments at 34–35; NARUC Initial Comments at 13–15; NRECA Initial Comments at 36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13–14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 16–17; US DOE Initial Comments at 16–18; WATT Coalition Initial Comments at 7.

¹⁴¹⁵ Ameren Initial Comments at 14; MISO Initial Comments at 29; PPL Initial Comments at 9–10; Utah Division of Public Utilities Initial Comments at 7; Xcel Initial Comments at 10.

¹⁴¹⁶ See ACORE Initial Comments at 8; AEE Initial Comments at 23; Certain TDUs Initial Comments at 16; Clean Energy Buyers Initial Comments at 17–18; DC and MD Offices of People's Counsel Initial Comments at 14; Eversource Initial Comments at 20; Georgia Commission Initial Comments at 5; ISO–NE Initial Comments at 28; ITC Initial Comments at 12; Mississippi Commission Initial Comments at 34–35; NARUC Initial Comments at 13–15; NRECA Initial Comments at 36; OMS Initial Comments at 5; Ørsted Initial Comments at 7; Pacific Northwest State Agencies Initial Comments at 13–14; PJM Initial Comments at 7, 76; Policy Integrity Initial Comments at 16–17; US DOE Initial Comments at 16–18; WATT Coalition Initial Comments at 7.

¹⁴¹⁷ MISO Initial Comments at 29; Utah Division of Public Utilities Initial Comments at 6; Xcel Initial Comments at 10.

¹⁴¹⁸ Dominion Initial Comments at 26–27; Duke Initial Comments at 16–17; MISO Initial Comments at 40; MISO TOs Initial Comments at 19; NESCOE Initial Comments at 35–36.

¹⁴¹⁹ ACEG Initial Comments at 7; ACORE Initial Comments at 8–9; GridLab Initial Comments at 23; PIOs Initial Comments at 19–20; Southeast PIOs Initial Comments at 47–48.

¹⁴²⁰ ELCON Initial Comments at 13; LADWP Initial Comments at 4; Pine Gate Initial Comments at 27–29; Vermont Electric and Vermont Transco Initial Comments at 3.

¹⁴²¹ In addition, while we decline to adopt a specific accuracy standard that data must meet in order to be "best available data," we note that a demonstration that a data source has historically proven to be relatively inaccurate would likely constitute evidence that such data is not best available data.

¹⁴¹⁰ NOPR, 179 FERC ¶ 61,028 at P 132.

¹⁴¹¹ Order No. 890, 118 FERC ¶ 61,119 at PP 501–503.

¹⁴¹² NYISO Initial Comments at 28 (citing NOPR, 179 FERC ¶ 61,028 at P 131).

¹⁴¹³ *Id.*

requirements will help ensure that data inputs are as accurate as possible, while also providing transmission providers with the flexibility to use best practices to develop data inputs that are appropriate for their transmission planning regions and to recognize the inherent uncertainty involved in planning transmission on a forward-looking basis.

641. With respect to the issue raised by PJM about revealing potentially confidential data to improve accuracy,¹⁴²² we reiterate, as discussed above, that consistent with Order No. 890's transparency transmission planning principle, transmission providers in each transmission planning region are required to disclose (subject to appropriate confidentiality protections) information and data inputs they use to create each Long-Term Scenario.¹⁴²³ The Commission has recognized that tension exists between ensuring transparency in transmission planning processes and protecting confidential information, including commercially sensitive information.¹⁴²⁴ The Commission has also noted that using resource-specific data that best reflect actual operations on the transmission system leads to more precise and effective transmission study results. In addition, the Commission has recognized that market participants who provide that information need to be assured that the confidential information they provide will be used for its intended purpose in planning the transmission system and will not be disclosed in a manner that harms them commercially. However, the Commission has found that, at the same time, the requirement in Order No. 890 for transmission providers to disclose to all customers and other stakeholders the basic methodology, criteria, assumptions, and data that underlie their transmission system plans to enable customers, other stakeholders, or an independent third-party to replicate the results of planning studies is essential to an open and transparent transmission planning process.¹⁴²⁵ Thus, the Commission has found that, without certain generator dispatch and economic information, for example, it becomes difficult or impossible to conduct meaningful load flow studies for some transmission planning purposes,¹⁴²⁶ and the competitive

playing field is tilted toward those who have this information and away from those who do not.¹⁴²⁷

642. The Commission therefore required in Order No. 890, and we apply that requirement to Long-Term Regional Transmission Planning in this final order, disclosure of the methodology, criteria, assumptions, data and other information that underlie transmission plans, including Long-Term Scenarios. We recognize that no bright line rule exists to determine the appropriate balance between ensuring transparency in the transmission planning processes and ensuring that confidential information is not disclosed inappropriately. Transmission providers may propose what they believe are appropriate confidentiality protections in their filings to comply with this final order, and the Commission will evaluate those proposals by using the established principles in Order No. 890, as well as precedent on existing confidentiality protections with respect to transmission planning that the Commission has previously found comply with the Order No. 890 principles, to guide its findings on whether such protections are appropriate.

643. With respect to the issue raised by ELCON and Pine Gate about timely data,¹⁴²⁸ we decline to adopt their suggestion to define precisely what "timely" means with respect to best available data because we believe flexibility is warranted given the diverse regional transmission planning processes to which this reform will apply. That is, we believe that updating data inputs may require different timelines depending on the transmission planning region and the specific data input, where each input may change on a different timeline. However, given the five-year duration of the Long-Term Regional Transmission Planning cycle, and the risk of data becoming stale, we require transmission providers to update their data inputs at least once at the outset of each Long-Term Regional Transmission Planning cycle.

644. With respect to National Grid's request to clarify the definition of "diverse" in the context of the requirement that data inputs must be developed using diverse and expert perspectives,¹⁴²⁹ we clarify that the term "diverse" specifically used in the context of data inputs indicates that the data inputs must represent a range of

data within the bounds of plausibility. We believe that this requirement will ensure that the *set* of Long-Term Scenarios that are developed from these data inputs will represent a reasonable range of probable future outcomes consistent with the requirement for plausibility.

8. Identification of Geographic Zones

a. NOPR Proposal

645. In the NOPR, the Commission proposed to require that each transmission provider, as part of its regional transmission planning process, consider whether to establish geographic zones within the transmission planning region that have the potential for development of large amounts of new generation. If transmission providers within a transmission planning region choose to establish geographic zones, then the Commission proposed to require the transmission provider to: (1) identify, with stakeholder input, specific geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios.¹⁴³⁰

646. The Commission preliminarily found that requiring the consideration and potential identification of geographic zones within Long-Term Scenarios assists transmission providers, transmission developers, and generation developers in coordinating their activities. The Commission stated that transmission providers would be able to better identify transmission needs driven by changes in the resource mix and demand by considering geographic zones that have the potential for the development of large amounts of new generation and where developers have already shown commercial interest. Further, the Commission stated that, using the information gained through the process described below to identify such geographic zones, transmission providers in each transmission planning region could then plan transmission facilities that would serve large concentrations of new generation in a more efficient or cost-effective manner.¹⁴³¹

647. The Commission proposed to require, as step one of the three-step geographic zone process, that transmission providers consider

¹⁴²² PJM Reply Comments at 22.

¹⁴²³ See *supra* Number and Development of Long-Term Scenarios section.

¹⁴²⁴ *Sw. Power Pool, Inc.*, 137 FERC ¶ 61,227 at P 20.

¹⁴²⁵ Order No. 890, 118 FERC ¶ 61,119 at P 471.

¹⁴²⁶ *Id.* P 478.

¹⁴²⁷ *Sw. Power Pool, Inc.*, 137 FERC ¶ 61,227 at P 20.

¹⁴²⁸ ELCON Initial Comments at 13; Pine Gate Initial Comments at 28–29.

¹⁴²⁹ National Grid Initial Comments at 14.

¹⁴³⁰ NOPR, 179 FERC ¶ 61,028 at P 145.

¹⁴³¹ *Id.* P 146.

whether to establish and include in the regional transmission planning process outlined in their OATTs the method that they will use to identify geographic zones within the transmission planning region. The Commission also proposed to require that transmission providers in each transmission planning region use this information to create a set of draft geographic zones, and that they post on their OASIS or other public website maps of the draft geographic zones, as well as the information used to create the draft geographic zones, for stakeholders' input.¹⁴³²

648. In addition, the Commission proposed to require transmission providers in each transmission planning region to consider this stakeholder feedback and modify the draft geographic zones as appropriate to produce a final list of designated geographic zones within the transmission planning region.¹⁴³³

649. The Commission proposed to require, in step two of the three-step geographic zone process, that transmission providers in each transmission planning region assess generation developers' commercial interest in developing generation within each designated geographic zone.¹⁴³⁴ The Commission proposed to require, in the final step of the three-step geographic zone process, that transmission providers in each transmission planning region incorporate the information from step one and step two regarding the designated geographic zones into their Long-Term Scenarios.¹⁴³⁵

b. Comments

650. Many commenters support the Commission's proposal to require each transmission provider, as part of its regional transmission planning process, to consider whether to: (1) identify, with stakeholder input, specific geographic zones within the transmission planning region that have the potential for development of large amounts of new generation; (2) assess generation developers' commercial interest in developing generation within the identified geographic zones; and (3) incorporate designated zones, and the identified commercial interest in each zone, into Long-Term Scenarios.¹⁴³⁶

Commenters assert that, compared to interconnection-related network upgrades identified on a case-by-case basis in the interconnection process, identifying and incorporating geographic zones into Long-Term Scenarios would save consumers money by identifying more efficient or cost-effective transmission facilities to connect areas with the potential for low cost generation to load centers and reduce congestion and generator curtailment.¹⁴³⁷ Further, commenters note the success of previous planning efforts in ERCOT, MISO, CAISO, and ISO-NE to incorporate geographic zones into their transmission planning efforts.¹⁴³⁸

651. Some commenters highlight the importance of this proposed reform for remotely located renewable resources generally, and more specifically for offshore wind, which is constrained to lease areas auctioned by the Bureau of Ocean Energy Management.¹⁴³⁹ For example, Ørsted argues that the location and approximate resource potential of offshore wind is well understood and the failure to proactively plan the necessary transmission would result in higher costs to ratepayers.¹⁴⁴⁰ BP further contends that the geographic zones in which National Interest Electric Transmission Corridors are likely to be established also merit inclusion in transmission planning.¹⁴⁴¹

652. Some commenters support the proposal but urge the Commission to *require* the identification of geographic zones and planning transmission to integrate generation in those zones rather than just requiring transmission

providers to *consider* whether to identify geographic zones.¹⁴⁴² Acadia Center and CLF argue that the Commission should require the identification and creation of geographic zones in areas where the majority of states have binding greenhouse gas emission reduction or renewables mandates, which could result in fewer transmission corridors being built, thereby reducing costs, siting challenges, and benthic environmental impacts.¹⁴⁴³ Acadia Center and CLF assert that, without mandatory identification and establishment of geographic zones, there is a significant risk that adequate transmission will not be built to accommodate state emission reduction and renewables mandates in a cost-effective or efficient way.¹⁴⁴⁴

653. In contrast, other commenters emphasize that they support the proposal to require transmission providers to *consider* identifying geographic zones rather than to actually identify such geographic zones.¹⁴⁴⁵ Such commenters assert that providing the option to identify geographic zones would allow transmission providers to determine, with their stakeholders, what is right for their transmission planning region.¹⁴⁴⁶

654. Other commenters express concerns with the idea of incorporating geographic zones with the potential for large amounts of generation into regional transmission planning, but do not oppose the proposal so long as it is optional.¹⁴⁴⁷ For example, NESCOE and

¹⁴⁴² Acadia Center and CLF Initial Comments at 13–15; Amazon Initial Comments at 6–7; California Water Initial Comments at 16; Center for Biological Diversity Initial Comments at 13–15; City of New York Initial Comments at 7–8; Handy Law Initial Comments at 12; Invenergy Reply Comments at 9–10; SEIA Initial Comments at 11–12; Shell Initial Comments at 23.

¹⁴⁴³ Acadia Center and CLF Initial Comments at 13–14.

¹⁴⁴⁴ *Id.* at 13.

¹⁴⁴⁵ *See, e.g.,* Ameren Initial Comments at 15–16; American Municipal Power Initial Comments at 34–35; Clean Energy Associations Initial Comments at 13; EEI Initial Comments at 15; ISO-NE Initial Comments at 30; ITC Initial Comments at 5, 13–17; MISO Initial Comments at 30; Nebraska Commission Initial Comments at 6–7; NESCOE Initial Comments at 37; NRECA Initial Comments at 37; New York Commission and NYSERDA Initial Comments at 14–15; NYISO Initial Comments at 29–30; Ørsted Initial Comments at 7; US DOE Initial Comments at 18; Western PIOs Initial Comments at 31–32.

¹⁴³⁷ *See, e.g.,* ENGIE Initial Comments at 4; Eversource Initial Comments at 21–22; ITC Initial Comments at 13–17; Northwest and Intermountain Initial Comments at 5–6; NYISO Initial Comments at 29–30.

¹⁴³⁸ *See, e.g.,* ENGIE Initial Comments at 4; Eversource Initial Comments at 21–22.

¹⁴³⁹ *See, e.g.,* BP Initial Comments at 4, 7–8; Clean Energy Buyers Initial Comments at 18; New York Transco Initial Comments at 5–6; Ørsted Initial Comments at 7–8.

¹⁴⁴⁰ *See, e.g.,* Ørsted Initial Comments at 7–8.

¹⁴⁴¹ BP Initial Comments at 7 (citing 16 U.S.C. 824p).

¹⁴⁴⁶ *See, e.g.,* EEI Initial Comments at 15; ISO-NE Initial Comments at 30; MISO Initial Comments at 30; New York Commission and NYSERDA Initial Comments at 14–15; NYISO Initial Comments at 32.

¹⁴⁴⁷ APPA Initial Comments at 29–30; Dominion Initial Comments at 28–29; Georgia Commission Initial Comments at 6; Large Public Power Initial Comments at 22; National Grid Initial Comments at 16–17; NESCOE Initial Comments at 38; SERTP Sponsors Initial Comments at 27; SPP Market Monitor Initial Comments at 11–12; TANC Initial Comments at 10.

¹⁴³² *Id.* PP 147–148.

¹⁴³³ The Commission noted that, while it referred to multiple “zones,” subsequent to stakeholder feedback, the final list may contain only one designated geographic zone. *Id.* P 149.

¹⁴³⁴ *Id.* P 150.

¹⁴³⁵ *Id.* P 151.

¹⁴³⁶ Ameren Initial Comments at 15; American Municipal Power Initial Comments at 35; Clean Energy Associations Initial Comments at 13; EEI

National Grid assert that the proposed requirements for each of the three steps is overly prescriptive and could be included in a final order as guidance, but not as a mandate.¹⁴⁴⁸

655. Several commenters urge the Commission to provide flexibility in any process for considering and potentially identifying geographic zones.¹⁴⁴⁹ For example, Michigan Commission states that the proposed three-step process in the NOPR is highly prescriptive and overly burdensome, and instead the Commission should provide greater flexibility to ensure that generation siting assumptions included in Long-Term Scenarios are developed transparently in collaboration with state regulators, generation utilities, and resource planners.¹⁴⁵⁰

656. Several commenters suggest modifications to the NOPR proposal.¹⁴⁵¹ For example, Vistra contends that the NOPR proposal could be improved through the use of open seasons or other comparable tools to elicit concrete commitments from generator developers.¹⁴⁵² Other commenters argue that the NOPR proposal should be modified to involve a subscription model in which prospective generation resources within the zone indicate their willingness to pay for transmission to the zone.¹⁴⁵³ Although PJM opposes the NOPR proposal, PJM argues that these alternative proposals offered by Vistra and New Jersey Commission have merit and are worthy of further dialogue.¹⁴⁵⁴

657. Regarding the specific steps in the NOPR proposal for identifying geographic zones, several commenters support the proposal to provide all stakeholders, including relevant Federal and state siting authorities, with a meaningful opportunity to provide

input on the draft geographic zones.¹⁴⁵⁵ Other commenters, however, assert that the Commission should provide a clearer role for states and other stakeholders to participate earlier in the process of identifying geographic zones.¹⁴⁵⁶

658. Some commenters argue that the NOPR proposal regarding what information transmission providers should use to gauge commercial interest in geographic zones is overly prescriptive and that the information would be too speculative to be an accurate indicator of commercial interest.¹⁴⁵⁷ Several commenters urge the Commission to increase the transparency of the NOPR proposal.¹⁴⁵⁸ For example, US DOE recommends that the Commission specify minimum standards for reporting the attributes of each geographic zone.¹⁴⁵⁹

659. Several commenters oppose the proposal to require transmission providers to consider whether to identify geographic zones with the potential for large amounts of generation.¹⁴⁶⁰ For example, APS argues that the proposal may not be appropriate due to the speculative nature of the identification of geographic zones and the long-term nature of planning and building transmission infrastructure.¹⁴⁶¹ Idaho Power is concerned that the NOPR proposal will create a significant level of work for transmission providers that

would outweigh the minor benefits developers would receive from the data.¹⁴⁶²

660. PJM opposes the NOPR proposal, which it describes as an arbitrary and inflexible process that fails to account for regional differences and that will require transmission providers to draw lines on a map and commit to these areas for 20 years.¹⁴⁶³ PJM states that the information from the geographic zones will be poor compared to information in the marketplace, including nearer term decisions of interconnection customers.¹⁴⁶⁴ PJM states that an alternative, more case-specific flexible approach that builds on and is better synchronized with the transmission provider's interconnection queue process and market developments, and accommodates topologies as diverse as those in PJM, is a better solution.¹⁴⁶⁵ For example, PJM suggests that the PJM State Agreement Approach is a better way to facilitate clusters of renewable energy interconnections by finding states that are willing to sponsor the new transmission to help fulfill a renewable energy policy.¹⁴⁶⁶

661. Several state commissions express concerns that the NOPR proposal would give undue preference to certain kinds of resources.¹⁴⁶⁷ For example, North Dakota Commission argues that the NOPR proposal would bias transmission planning towards one type of generation, encourage speculative build-out of transmission, and prevent visibility into the cost of other generation/transmission combinations, which will result in under-utilized transmission and additional costs to ratepayers with little benefit.¹⁴⁶⁸

662. North Carolina Commission and Staff assert that the NOPR proposal is an unwarranted intrusion into state jurisdiction over generation and fails to acknowledge state authority over utility generation, resource portfolios, and

¹⁴⁴⁸ NESCOE Initial Comments at 38; National Grid Initial Comments at 16.

¹⁴⁴⁹ See, e.g., APS Initial Comments at 5; ISO-NE Initial Comments at 30; Michigan Commission Initial Comments at 6; MISO Initial Comments at 42; MISO TOs Initial Comments at 32; NARUC Initial Comments at 17; New Jersey Commission Initial Comments at 15; NYISO Initial Comments at 3–4.

¹⁴⁵⁰ Michigan Commission Initial Comments at 6.

¹⁴⁵¹ Acadia Center and CLF Initial Comments at 15–16; California Energy Commission Initial Comments at 2–3; Center for Biological Diversity Initial Comments at 13–16; Clean Energy Associations Initial Comments at 24–25; Illinois Commission Initial Comments at 9–11; Large Public Power Initial Comments at 26; Microgrid Resources Coalition Initial Comments at 4–6; New Jersey Commission Initial Comments at 16–17; Vistra Initial Comments at 24.

¹⁴⁵² Vistra Initial Comments at 24.

¹⁴⁵³ Clean Energy Associations Initial Comments at 24–25; Large Public Power Initial Comments at 26; New Jersey Commission Initial Comments at 16–17.

¹⁴⁵⁴ PJM Reply Comments at 29–30, 31–32.

¹⁴⁵⁵ ISO/RTO Council Initial Comments at 8; NARUC Initial Comments at 16–17; National Grid Initial Comments at 17; Nebraska Commission Initial Comments at 7; SEIA Initial Comments at 12–13; Shell Initial Comments at 25.

¹⁴⁵⁶ Acadia Center and CLF Initial Comments at 12–13; AEE Initial Comments at 24–25; Amazon Initial Comments at 7; CAISO Initial Comments at 4–5, 28–29, 31; DC and MD Offices of People's Counsel Initial Comments at 15–16; Interwest Initial Comments at 9; ISO-NE Initial Comments at 29; National Grid Initial Comments at 17–18; NESCOE Initial Comments at 38–39; Nevada Commission Initial Comments at 9–10; SERTP Sponsors Initial Comments at 27.

¹⁴⁵⁷ See, e.g., Middle River Power Initial Comments at 3; MISO Initial Comments at 43; PJM Initial Comments at 84.

¹⁴⁵⁸ Amazon Initial Comments at 8; Shell Initial Comments at 23–24; US DOE Initial Comments at 24–25.

¹⁴⁵⁹ US DOE Initial Comments at 20.

¹⁴⁶⁰ APS Initial Comments at 5–7; Arizona Commission Initial Comments at 8; CAISO Initial Comments at 27–28; Consumer Organizations Initial Comments at 3–7; Duke Initial Comments at 4, 18–19; Idaho Power Initial Comments at 5; Indicated PJM TOs Initial Comments at 3–4, 12–13; ISO/RTO Council Initial Comments at 7; LADWP Initial Comments at 4; Louisiana Commission Initial Comments at 24–25; Michigan Commission Initial Comments at 5–6; Microgrid Resources Initial Comments at 5; North Carolina Commission and Staff Initial Comments at 8–10; North Dakota Commission Initial Comments at 4–5; Ohio Commission Federal Advocate Initial Comments at 7–8.

¹⁴⁶¹ APS Initial Comments at 6–7.

¹⁴⁶² Idaho Power Initial Comments at 5.

¹⁴⁶³ PJM Initial Comments at 77–78.

¹⁴⁶⁴ *Id.* at 77.

¹⁴⁶⁵ *Id.* at 7.

¹⁴⁶⁶ *Id.* at 79–82 (citing PJM Operating Agreement, Schedule 6, section 1.5.9).

¹⁴⁶⁷ Arizona Commission Initial Comments at 8; Louisiana Commission Initial Comments at 24–25; Louisiana Commission Reply Comments at 11–12; Michigan Commission Initial Comments at 5–6; North Carolina Commission and Staff Initial Comments at 10–13; North Dakota Commission Initial Comments at 4; Ohio Commission Federal Advocate Initial Comments at 7–8; Pennsylvania Commission Initial Comments at 7–8.

¹⁴⁶⁸ North Dakota Commission Initial Comments at 4.

integrated resource planning.¹⁴⁶⁹ Similarly, Ohio Commission Federal Advocate asserts that the NOPR proposal exceeds the Commission's authority and interferes with Ohio's ability to maintain its competitive retail electric service law.¹⁴⁷⁰ Mississippi Commission states that decisions to develop such zones within a state should be left to the state.¹⁴⁷¹

Pennsylvania Commission argues that the geographic zones used for Long-Term Scenarios could frustrate a state's legitimate policy choices in establishing, for example, economic development zones designed to encourage developers to site generation in specific areas, by favoring another state's policy choices.¹⁴⁷² TAPS opposes any requirement to undertake a process to consider and identify remote geographic zones where state or local laws require local generating resources rather than remote resources.¹⁴⁷³

663. Many commenters argue that the NOPR proposal would be duplicative of, or would interfere with, existing processes.¹⁴⁷⁴ AEE states that the consideration of geography in developing long-term regional transmission plans should occur as a natural outgrowth of more effective regional transmission planning and that a specific requirement to identify geographic zones could have unintended consequences.¹⁴⁷⁵ AEE further asserts that some of the factors that the NOPR proposes to require transmission providers to incorporate in their Long-Term Scenarios inherently require them to consider what geographic areas are ripe for low-cost generation development but are isolated or otherwise transmission constrained.¹⁴⁷⁶ Similarly, Indicated PJM TOs argue that it is unnecessary to

require the identification of geographic zones in Long-Term Regional Transmission Planning because transmission providers necessarily will rely on driving factors (e.g., public policy goals) that will determine where renewable resources will be developed.¹⁴⁷⁷ According to Duke, the categories of factors proposed in the NOPR already capture generator interconnections, so it is unclear what this additional process will add.¹⁴⁷⁸

664. Several commenters argue that some transmission planning processes already incorporate the identification of geographic zones, and those existing processes should be allowed to continue.¹⁴⁷⁹ ISO-NE claims that transmission providers' planning constructs may already include rules that allow for assessing and identifying geographic zones with potential for high renewable development, rendering a separate process redundant or unnecessary.¹⁴⁸⁰ SPP states that the NOPR proposal would duplicate SPP's current process to some extent and that it would not be practical to do both.¹⁴⁸¹ Similarly, CAISO argues that the NOPR proposal is overly prescriptive and would interfere with California's existing processes, which are working effectively.¹⁴⁸² New York TOs note that New York's transmission planning processes already include the evaluation of geographic zones expected to see significant growth in generation or changes in load and incorporate state involvement.¹⁴⁸³ Mississippi Commission asserts that MISO already considers geographic zones for new generation.¹⁴⁸⁴

c. Commission Determination

665. We decline to adopt the proposed requirement that each transmission provider, as part of its regional transmission planning process, consider whether to establish geographic zones within the transmission planning region that have the potential for development of large amounts of new generation. We are persuaded by commenters that finalizing and requiring the NOPR

proposal is not warranted at this time. Further, given the other requirements in this final order, such as the requirement for transmission providers to plan for factors affecting supply and demand, we agree with commenters that adopting this proposed requirement is not necessary at this time to ensure that Long-Term Regional Transmission Planning ensures just and reasonable rates. We also agree with commenters that the prescriptive nature of the proposed three-step process could unintentionally impede existing efforts to incorporate geographic zones into regional transmission planning.

666. Although we are not adopting the NOPR proposal, we encourage transmission providers to consider geographic zones that have the potential for development of large amounts of new generation as part of their regional transmission planning process. As such, transmission providers in a transmission planning region may propose to identify geographic zones as part of Long-Term Regional Transmission Planning on compliance with this final order, provided that they demonstrate that their process for identifying such geographic zones is consistent with or superior to the Long-Term Regional Transmission Planning requirements established herein.

D. Evaluation of the Benefits of Regional Transmission Facilities

667. In this final order, we require transmission providers, as part of Long-Term Regional Transmission Planning, to measure seven specified benefits that were enumerated in the NOPR ("set of seven required benefits" or "required benefits") in each Long-Term Scenario. We also allow transmission providers to propose on compliance to measure additional benefits as part of Long-Term Regional Transmission Planning. In addition, we require transmission providers to use those measured benefits when evaluating Long-Term Regional Transmission Facilities to determine whether they more efficiently or cost-effectively address Long-Term Transmission Needs.¹⁴⁸⁵

668. This section of the final order discusses the requirements that we adopt governing transmission providers' measurement and use of benefits in Long-Term Regional Transmission Planning. Specifically, we discuss: (1) the requirement to use a set of seven required benefits; (2) the required benefits, themselves; (3) the requirement

¹⁴⁶⁹ North Carolina Commission and Staff Initial Comments at 8.

¹⁴⁷⁰ Ohio Commission Federal Advocate Initial Comments at 7 (quoting Ohio Commission Federal Advocate ANOPR Comments at 8).

¹⁴⁷¹ Mississippi Commission Reply Comments at 10.

¹⁴⁷² Pennsylvania Commission Initial Comments at 7–8.

¹⁴⁷³ TAPS Initial Comments 9–10.

¹⁴⁷⁴ AEE Initial Comments at 8; APS Initial Comments at 5; CAISO Initial Comments at 4–5; Duke Initial Comments at 18–19; Illinois Commission Initial Comments at 9–11; Indicated PJM TOs Initial Comments at 12; ISO-NE Initial Comments at 30; ISO/RTO Council Initial Comments at 7; MISO TOs Initial Comments at 32; Mississippi Commission Reply Comments at 10; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 37; Nevada Commission Initial Comments at 10; New York TOs Initial Comments at 12; NYISO Initial Comments at 33; SPP Initial Comments at 12–13; TAPS Initial Comments 8–10; Xcel Initial Comments at 10–11.

¹⁴⁷⁵ AEE Initial Comments at 8.

¹⁴⁷⁶ *Id.* at 23–24.

¹⁴⁷⁷ Indicated PJM TOs Initial Comments at 12.

¹⁴⁷⁸ Duke Initial Comments at 18.

¹⁴⁷⁹ *See, e.g.*, CAISO Initial Comments at 27–33; ISO-NE Initial Comments at 30; MISO TOs Initial Comments at 32; Nebraska Commission Initial Comments at 6; NESCOE Initial Comments at 37; Nevada Commission Initial Comments at 10; New York TOs Initial Comments at 12; NYISO Initial Comments at 33; SPP Initial Comments at 12–13.

¹⁴⁸⁰ ISO-NE Initial Comments at 30.

¹⁴⁸¹ SPP Initial Comments at 12–13.

¹⁴⁸² CAISO Initial Comments at 4–5, 27–33.

¹⁴⁸³ New York TOs Initial Comments at 12.

¹⁴⁸⁴ Mississippi Commission Reply Comments at 10.

¹⁴⁸⁵ As discussed in the Development of Long-Term Scenarios section *supra*, transmission providers must also use these benefits to inform their identification of Long-Term Transmission Needs.

to include a general description of how transmission providers will measure each of the benefits that the final order requires, as well as any additional benefits that they may propose, in their OATTs; (4) the requirements related to the minimum time horizon over which transmission providers must calculate the benefits of Long-Term Regional Transmission Facilities; (5) the evaluation of the benefits of portfolios of Long-Term Regional Transmission Facilities; and (6) other issues related to benefits.

1. Requirement for Transmission Providers To Use a Set of Seven Required Benefits

a. NOPR Proposal

669. In the NOPR, the Commission proposed a list of benefits that

transmission providers in each transmission planning region may consider in Long-Term Regional Transmission Planning and cost allocation processes, which included: (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12)

increased market liquidity.¹⁴⁸⁶ The NOPR provided a description of each of these benefits categories as well as a method to calculate benefits in each category.¹⁴⁸⁷

670. The Commission explained that it was not proposing to make the list of potential benefits mandatory or exhaustive and that transmission providers would have flexibility to propose which benefits to use as part of their Long-Term Regional Transmission Planning.¹⁴⁸⁸

671. The 12 potential benefits described in the NOPR are:

Number	Benefit	Description
1	Avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement.	Reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities.
2a	Reduced loss of load probability [OR next benefit].	Reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load (if planning reserve margin is constant), resulting in benefit of reduced expected unserved energy by customer value of lost load.
2b	Reduced planning reserve margin [OR prior benefit].	While holding loss of load probabilities constant, system operators can reduce their resource adequacy requirements (i.e., planning reserve margins), resulting in a benefit of reduced capital cost of generation needed to meet resource adequacy requirements.
3	Production cost savings	Reduction in production costs, including savings in fuel and other variable operating costs of power generation, that are realized when transmission facilities allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies; also, reduction in market prices as lower-cost suppliers set market clearing prices; when adjusted to account for purchases and sales outside the region, called adjusted production cost savings.
4	Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads, thereby reducing total energy necessary to meet demand.
5	Reduced congestion due to transmission outages.	Reduced production costs during transmission outages that significantly increase transmission congestion.
6	Mitigation of extreme events and system contingencies.	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages, through more robust transmission system reducing high-cost generation and emergency procurements necessary to support the system.
7	Mitigation of weather and load uncertainty.	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns.
8	Capacity cost benefits from reduced peak energy losses.	Reduced energy losses during peak load reduces generation capacity investment needed to meet the peak load and transmission losses.
9	Deferred generation capacity investments.	Reduced costs of needed generation capacity investments through expanded import capability into resource-constrained areas.
10	Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location (e.g., low permitting costs, low-cost sites on which plants can be built, access to existing infrastructure, low labor costs, low fuel costs, access to valuable natural resources, locations with high-quality renewable energy resources).
11	Increased competition	Reduced bid prices in wholesale electricity markets due to increased competition among generators and reduced overall market concentration/market power.
12	Increased market liquidity	Reduced transaction costs (e.g., bid-ask spreads) of bilateral transactions, increased price transparency, increased efficiency of risk management, improved contracting, and better clarity for Long-Term Regional Transmission Planning and investment decisions through increased number of buyers and sellers able to transact with each other as a result of transmission expansion.

¹⁴⁸⁶ NOPR, 179 FERC ¶ 61,028 at P 185. As more fully described below, the Commission is making modifications to the list of benefits in this final order. Therefore, we clarify for the reader how we refer to each of those benefits in this section. We

refer to benefits 1–6 as “Benefit 1,” “Benefit 2,” etc. We refer to Benefit 7, “mitigation of weather and load uncertainty” as NOPR Benefit 7. We refer to “(8) capacity cost benefits from reduced peak energy losses” as “NOPR Benefit 8,” “Final Order

Benefit 7,” and “Benefit 7.” We refer to benefits 9–12 as “Benefit 9,” Benefit 10,” etc.

¹⁴⁸⁷ *Id.* PP 189–225.

¹⁴⁸⁸ *Id.* P 184.

672. While the Commission did not propose to require use of any specific benefits in the NOPR, it sought comment on whether transmission providers should be required to use some or all of the potential benefits described in the NOPR as a minimum set of benefits for their Long-Term Regional Transmission Planning process.¹⁴⁸⁹

b. Comments

673. Many commenters support the NOPR approach of providing illustrative benefits rather than mandating the use of certain benefits.¹⁴⁹⁰ Indicated PJM TOs contend that the NOPR proposal would advance the Commission's goals better than a more prescriptive proposal.¹⁴⁹¹ SERTP Sponsors and Southern argue that the Commission should not impose a minimum set of benefits because existing state-regulated integrated resource planning processes adequately examine some of the proposed benefits, and that some of the proposed benefits would harm existing integrated resource planning processes or are only appropriate for RTO/ISO regions.¹⁴⁹² LADWP asserts that some or all of the identified benefits will be considered as part of the normal transmission planning process without a requirement.¹⁴⁹³ Dominion asserts that the question arises of who will judge whether a transmission project addresses the NOPR's proposed list of benefits and that such debates could be

time-consuming and further delay projects and drive up costs.¹⁴⁹⁴ Dominion states that transmission providers should be permitted to identify the benefits that they will consider in conducting Long-Term Regional Transmission Planning but retain flexibility to apply the specific benefits that are most appropriate given each transmission provider's individual circumstances.¹⁴⁹⁵

674. TAPS supports requiring transmission providers to evaluate production cost modeling but opposes requiring transmission providers to consider any other benefits in order to allow for regional flexibility.¹⁴⁹⁶ Northwest and Intermountain and NYISO ask that the final order confirm that the 12 illustrative benefits are neither mandatory nor exhaustive.¹⁴⁹⁷ California Municipal Utilities state that requiring the consideration of all 12 benefits proposed in the NOPR would misapprehend the state and local nature of resource portfolio planning and fail to account for the costs of such prescriptive measures and the need for consumer protection measures to guard against speculative transmission projects.¹⁴⁹⁸

675. OMS urges the Commission to clarify that transmission providers will have sufficient flexibility to use different sets of benefit metrics in different transmission planning cycles.¹⁴⁹⁹ Relatedly, Xcel states that for any specific study, portfolio, or transmission project, all benefits do not need to be calculated and, in some cases, calculating additional benefits may be costly, time consuming, and contentious and provide little added value.¹⁵⁰⁰

676. Many of the commenters that support an illustrative approach emphasize the importance of regional flexibility.¹⁵⁰¹ US Chamber of

Commerce states that flexibility will allow transmission planning regions to consider benefits that best align with their respective market structures.¹⁵⁰² MISO states that, without flexibility, it may not be able to move forward with the transmission projects of the greatest benefit and value to MISO and its stakeholders, noting that benefits used to meet criteria for its recent Long-Range Transmission Planning projects are not specified in its OATT.¹⁵⁰³ MISO, NYISO, and SPP argue that transmission providers and their stakeholders ought to determine what the benefits evaluated for specific transmission projects or sets of projects should be.¹⁵⁰⁴ NARUC, New York TOs, and Pennsylvania Commission agree, emphasizing consultation with states.¹⁵⁰⁵

677. Entergy urges the Commission to affirm its commitment to providing transmission planning regions with flexibility in terms of how they identify, consider, and calculate benefits. Entergy further urges the Commission to adopt guiding principles to aid transmission providers in identifying their own benefits.¹⁵⁰⁶ Entergy argues that the Commission should recognize that not all benefits are appropriate in all jurisdictions and that some states will want to prioritize transmission projects that reduce customer bills.¹⁵⁰⁷

678. SPP argues that how and when transmission benefits are calculated and incorporated in any regional transmission planning assessment should be at the discretion of each transmission provider and its stakeholders. Specifically, SPP argues that the effort required to incorporate additional benefit metrics into its current transmission planning process cannot be accommodated within its current process timeline.¹⁵⁰⁸

679. Mississippi Commission argues that any required benefits would be arbitrary and some metrics may not be applicable at times.¹⁵⁰⁹ National Grid

20–21; National Grid Initial Comments at 26; Nebraska Commission Initial Comments at 7; New York TOs Initial Comments at 15; Pennsylvania Commission Initial Comments at 9; SPP Initial Comments at 18; US Chamber of Commerce Initial Comments at 7; Vistra Initial Comments at 15; Xcel Initial Comments at 12.

¹⁵⁰² US Chamber of Commerce Initial Comments at 7.

¹⁵⁰³ MISO Initial Comments at 9.

¹⁵⁰⁴ MISO Initial Comments at 9–10; NYISO Initial Comments at 39; SPP Initial Comments at 18.

¹⁵⁰⁵ NARUC Initial Comments at 21–22; New York TOs Initial Comments at 15; Pennsylvania Commission Initial Comments at 9.

¹⁵⁰⁶ Entergy Initial Comments at 21.

¹⁵⁰⁷ *Id.*

¹⁵⁰⁸ SPP Initial Comments at 18.

¹⁵⁰⁹ Mississippi Commission Initial Comments at 35–36.

¹⁴⁸⁹ *Id.* P 188.

¹⁴⁹⁰ Ameren Initial Comments at 19; APPA Initial Comments at 31; APS Initial Comments at 9; Dominion Initial Comments at 34; Duke Initial Comments at 22–23; EEI Initial Comments at 19–20; Eversource Initial Comments at 25; Georgia Commission Initial Comments at 6–7; Idaho Commission Initial Comments at 4; Idaho Power Initial Comments at 7–8; Illinois Commission Initial Comments at 13–14; Indiana Commission Initial Comments at 6; Indicated PJM TOs Initial Comments at 17; ISO–NE Initial Comments at 5, 33–34; LADWP Initial Comments at 5; Louisiana Commission Reply Comments at 9–10; Michigan Commission Initial Comments at 6; MISO Initial Comments at 9, 51–52; Mississippi Commission Initial Comments at 36; NARUC Initial Comments at 20–21; National Grid Initial Comments at 26; North Carolina Commission and Staff Initial Comments at 7; Nebraska Commission Initial Comments at 7; New York TOs Initial Comments at 15; NRECA Initial Comments at 43–45; NYISO Initial Comments at 9, 37–38; OMS Initial Comments at 7–8; Pacific Northwest Utilities Initial Comments at 8; Pennsylvania Commission Initial Comments at 9; SERTP Sponsors Initial Comments 29–30; Southern Initial Comments at 24; TANC Initial Comments at 16; TAPS Initial Comments at 3, 14; US Chamber of Commerce Initial Comments at 7; Vermont State Entities Initial Comments at 7; Virginia Commission Staff Initial Comments at 5; Vistra Initial Comments at 15; Xcel Initial Comments at 12.

¹⁴⁹¹ Indicated PJM TOs Initial Comments at 17.

¹⁴⁹² SERTP Sponsors Initial Comments 29–30; Southern Initial Comments at 25–27.

¹⁴⁹³ LADWP Initial Comments at 5.

¹⁴⁹⁴ Dominion Initial Comments at 34.

¹⁴⁹⁵ *Id.*

¹⁴⁹⁶ TAPS Initial Comments at 3, 14.

¹⁴⁹⁷ Northwest and Intermountain Initial Comments at 16; NYISO Initial Comments at 39.

¹⁴⁹⁸ California Municipal Utilities Reply Comments at 5–6.

¹⁴⁹⁹ OMS Initial Comments at 8.

¹⁵⁰⁰ Xcel Initial Comments at 12.

¹⁵⁰¹ Ameren Reply Comments at 16–17 (citing MISO Initial Comments at 9); APS Initial Comments at 9; Dominion Initial Comments at 34; Duke Initial Comments at 22–23; EEI Initial Comments at 19–20; Eversource Initial Comments at 25; Entergy Reply Comments at 3; Idaho Commission Initial Comments at 4; Idaho Power Initial Comments at 7–8; Illinois Commission Initial Comments at 13–14; Indiana Commission Initial Comments at 6–7; Large Public Power Initial Comments at 28; ISO–NE Initial Comments at 33–34; Massachusetts Attorney General Initial Comments at 12, 15; MISO Initial Comments at 9; Mississippi Commission Initial Comments at 35–36; NARUC Initial Comments at

argues that flexibility will allow transmission providers to adapt more readily to changes in state policy drivers, prevent the requirements of Long-Term Regional Transmission Planning from becoming dated, and allow benefits and cost allocation discussions to be synchronized.¹⁵¹⁰ Duke contends that allowing regional flexibility may help to mitigate some disputes within transmission planning regions over what benefits to measure and how to measure them. Moreover, Duke argues that regional flexibility is critical to ensuring that each benefit metric used is relevant and calculable for each transmission planning region, particularly given differences between RTO/ISO and non-RTO/ISO regions. Duke contends that regions must not be forced into accepting and implementing benefits metrics that they have not vetted or on which they do not have consensus.¹⁵¹¹

680. MISO, while stating its preference for flexibility in identifying benefits, also states that it would support identifying and using a general set of benefit metrics that capture key areas of transmission value, such as reliability and resilience, production cost savings, and avoided resource and/or transmission investment, assuming that each transmission planning region may determine how to calculate each metric and how each applies during a transmission assessment, as well as allowing for different benefit metrics not part of that “general set” to be applied when warranted.¹⁵¹²

681. Some commenters offer support for the illustrative benefits without suggesting that they be required.¹⁵¹³ PG&E states that CAISO’s transmission planning process currently evaluates several of the same benefits, either routinely or on a case-specific basis, and that PG&E supports the continued flexibility the NOPR envisions for RTO/ISOs.¹⁵¹⁴

682. In contrast, many commenters support the Commission requiring that transmission providers consider a minimum list of benefits for Long-Term Regional Transmission Planning.¹⁵¹⁵

PIOs argue that most of the benefits outlined in the NOPR have broad support, even among those commenters that do not support a Commission requirement to consider a minimum set of benefits.¹⁵¹⁶

683. Clean Energy Associations and US Senator Schumer assert that the failure to adopt a minimum list of benefits risks skewing benefit-to-cost ratios against developing necessary transmission because all costs would be included in an evaluation but not all benefits would also be included.¹⁵¹⁷ Clean Energy Associations further state that failing to require the adoption of a minimum list of benefits could lead to higher costs in the long-term, as larger transmission projects with net benefits would not be selected.¹⁵¹⁸ Finally, Clean Energy Associations argue that, without a minimum list of benefits, significant disparities in regional identification of potential Long-Term Regional Transmission Facilities could have harmful spillover effects on coordinated activities such as interregional transmission coordination and affected systems studies.¹⁵¹⁹

684. Michigan State Entities argue that there must be some prescribed list of benefits, asserting that it would not

Scientists Reply Comments at 7–10; Cypress Creek Reply Comments at 7–8; DC and MD Offices of People’s Counsels Reply Comments at 3, 7–8; ELCON Initial Comments at 15; Enel Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Exelon Initial Comments at 16; Grid United Initial Comments at 2; Handy Law Initial Comments at 8; US House Republicans Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; ITC Initial Comments at 5, 18–22; Interwest Initial Comments at 12; Interwest Reply Comments at 6–7; Joint Consumer Advocates Initial Comments at 11; Kentucky Commission Chair Chandler Reply Comments at 7; Minnesota State Entities Initial Comments at 6; New England for Offshore Wind Initial Comments at 5; New Jersey Commission Initial Comments at 11–14; Pacific Northwest State Agencies Initial Comments at 16–17; PIOs Initial Comments at 27–28; PIOs Reply Comments at 7–8; Policy Integrity Initial Comments at 27; Policy Integrity Supplemental Comments at 4; R Street Initial Comments at 9; RMI Initial Comments at 1; RMI Supplemental Comments at 2; SEIA Initial Comments at 16–17; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27–28; US DOE Initial Comments at 30–33; US Senator Schumer Supplemental Comments at 1–2; US Senator Whitehouse Supplemental Comments at 2; US Senators Supplemental Comments at 2; WATT Coalition Initial Comments at 7.

¹⁵¹⁶ PIOs Initial Comments at 26, 41; PIOs Reply Comments at 7–8.

¹⁵¹⁷ Clean Energy Associations Initial Comments at 19; US Senator Schumer Supplemental Comments at 1–2.

¹⁵¹⁸ Clean Energy Associations Initial Comments at 19–20 (citing The Brattle Group, *Transmission Planning and Benefit-Cost Analyses*, at 26 (Apr. 2021)).

¹⁵¹⁹ Clean Energy Associations Initial Comments at 19.

force differently situated transmission providers to implement any specific policy, but instead would ensure that they take a “fair look” at transmission planning policies, including those using storage, that could produce substantial savings for customers.¹⁵²⁰ Interwest contends that a standard and comprehensive framework for evaluating benefits is necessary because an ad hoc approach could result in inconsistencies and an incomplete picture of a transmission project’s potential benefits.¹⁵²¹

685. Southeast PIOs urge the Commission to prescribe a set of benefits for use in benefit-cost analyses, starting with the entire list of benefits in the NOPR. Southeast PIOs argue that the transmission providers in the Southeast exploited the flexibility in establishing and assessing benefits that the Commission provided in Order No. 1000 to implement a straight cost comparison.¹⁵²² Southeast PIOs further state that minimum standards are necessary to produce actionable results; otherwise, Long-Term Regional Transmission Planning will devolve into a “box-checking exercise.”¹⁵²³ SREA argues that the Commission needs to set clear guidelines around benefit metrics to avoid opponents to the NOPR finding easy work-arounds.¹⁵²⁴

686. Similarly, R Street states that transmission providers should be required to use a minimum set of benefits because they lack the incentive to account for all system-wide benefits. R Street argues that proposing a benefits list for transmission providers to consider is the status quo and the Commission should expect little change without a benefits requirement.¹⁵²⁵ Concerned Scientists agree, claiming that the experience with Order No. 1000 implementation and the descriptions in the comments in response to the NOPR illustrate how transmission planning processes are resistant to changes when the Commission provides latitude for discretion.¹⁵²⁶ Concerned Scientists further contend that the discretion provided in the NOPR will allow a pattern of undue discrimination and unjust and unreasonable rates to persist

¹⁵²⁰ Michigan State Entities Reply Comments at 2.

¹⁵²¹ Interwest Reply Comments at 7.

¹⁵²² Southeast PIOs Initial Comments at 50.

¹⁵²³ Southeast PIOs Reply Comments at 23, 27.

¹⁵²⁴ SREA Reply Comments at 26 (citing Louisiana Commission Initial Comments at 17; Mississippi Commission Initial Comments at 11; Southern Initial Comments at 12).

¹⁵²⁵ R Street Initial Comments at 9.

¹⁵²⁶ Concerned Scientists Reply Comments at 7.

¹⁵¹⁰ National Grid Initial Comments at 26–27.

¹⁵¹¹ Duke Initial Comments at 22–23.

¹⁵¹² MISO Initial Comments at 9.

¹⁵¹³ Nevada Commission Initial Comments at 10–11; Pattern Energy Initial Comments at 14; PG&E Initial Comments at 7.

¹⁵¹⁴ PG&E Initial Comments at 7.

¹⁵¹⁵ ACORE Initial Comments at 12; ACORE Reply Comments at 6; ACORE Supplemental Comments at 1; AEE Initial Comments at 8, 25; AEP Initial Comments at 6, 23–25; Breakthrough Energy Initial Comments at 4, 21–22; Business Council for Sustainable Energy Initial Comments at 2, 5; Certain TDUs Initial Comments at 11–12; Clean Energy Buyers Reply Comments at 8–9; Concerned

that initially motivated the Commission to act.¹⁵²⁷

687. Some commenters assert that requiring the same benefits in different transmission planning regions will help increase interregional transmission coordination.¹⁵²⁸ Clean Energy Associations argue that it is important for transmission planning regions to have a common starting point in terms of which benefits they evaluate to facilitate greater interregional transmission coordination.¹⁵²⁹ Breakthrough Energy notes that load diversity—and its effect on reducing very expensive generation capacity costs—is a major and under-appreciated benefit of large-scale interregional transmission facilities.¹⁵³⁰ Grid United states that, without a minimum set of benefits criteria, disparate benefits in neighboring transmission planning regions could balkanize the grid and disrupt effective interregional transmission planning, emphasizing the need for a set of principles that outline benefits that are universal and necessary for effective long-term transmission planning.¹⁵³¹ Policy Integrity asserts that defining a uniform set of minimum benefits would facilitate better identification and selection of efficient and cost-effective transmission solutions and would ensure comparability of transmission expansion projects across different RTOs/ISOs, which will be particularly useful given the need to improve Interregional Transfer Capability.¹⁵³²

688. Relatedly, PJM states that, while it agrees that transmission providers should have flexibility to propose which benefits make sense to consider for their own transmission planning regions, the Commission should adopt a core set of benefits to be considered nationwide to ensure consistency.¹⁵³³ SREA notes that, in RTOs/ISOs, seams are perpetually a problem due to a lack of common national standards on benefits metrics and data inputs and asserts that the Commission should set minimum standards.¹⁵³⁴

689. Some commenters assert that a failure to consider sufficient benefits could result in higher costs and/or

unjust and unreasonable rates.¹⁵³⁵

According to Enel, without considering a larger number of benefits, transmission projects that would have large net benefits will not be selected if no benefits or even only a small number of potential benefits were compared against the upfront costs.¹⁵³⁶

690. Some commenters assert that a failure to require consideration of specific benefits will undermine other aspects of the NOPR's proposed reforms.¹⁵³⁷ Anbaric, for instance, argues that the NOPR falls far short of requiring comprehensive transmission planning, because it does not propose to mandate the use of any specific set of benefits.¹⁵³⁸ RMI contends that there is overwhelming evidence that transmission infrastructure provides multiple, diverse benefits, as well as established precedent that transmission costs should be allocated roughly commensurate with benefits. Therefore, RMI states, it would be illogical to allow transmission providers to ignore any benefits that transmission infrastructure offers, as it would lead to flawed investment decisions and defective cost allocation. RMI asserts that transmission providers should be required to quantify the full suite of known benefits of transmission infrastructure in Long-Term Regional Transmission Planning and that the list of 12 benefits in the NOPR is conservative and does not double-count benefits.¹⁵³⁹

691. AEE argues that several of the listed benefits are indisputably relevant to all transmission planners and that these benefits should form a core group of minimum considerations.¹⁵⁴⁰ AEE states that the Commission may wish to conduct additional fact-finding in this docket to consider whether additional benefits cut across all markets and transmission planning regions or whether it is necessary to require each region to identify region-specific

benefits for inclusion.¹⁵⁴¹ Hannon Armstrong states that the Commission indicated that each of the 12 benefits listed in the NOPR has the potential to provide a meaningful contribution to offset the cost of transmission and recommends that, absent any double-counting in this list, the Commission should require each of these benefits to be evaluated.¹⁵⁴² ITC argues that the Commission should adopt as minimum benefit criteria for project evaluation those used in the recently approved MISO Long-Range Transmission Plan process.¹⁵⁴³

692. Southeast PIOs claim that the Commission must establish a set of minimum benefits for transmission providers to incorporate in their assessment of regional transmission facilities to ensure that regional transmission facilities are accurately represented in the transmission planning process.¹⁵⁴⁴ Southeast PIOs contend that a regional transmission planning process that quantifies and fully accounts for benefits of regional transmission alternatives would provide a measure of assurance to regulators and stakeholders that such alternatives were evaluated appropriately.¹⁵⁴⁵ In response to Southern and SERTP, Southeast PIOs argue that quantifying the listed benefits does not itself make resource decisions; the benefits are meant to determine the value proposition of alternative regional transmission facilities.¹⁵⁴⁶

693. GridLab states that the Commission should require transmission providers to justify why their transmission solution evaluation frameworks omit any categories of benefits in relation to a standard list of benefits like those proposed in the NOPR.¹⁵⁴⁷ Pattern Energy agrees and notes that a “common starting point” would lower barriers to entry for market participants that do business in multiple transmission planning regions. Moreover, Pattern Energy argues that a required set of standardized benefits would facilitate a more transparent transmission planning process, as developers would have a baseline knowledge of any single transmission provider's transmission planning

¹⁵²⁷ *Id.* at 8–9.

¹⁵²⁸ Breakthrough Energy Initial Comments at 22–23; California Commission Initial Comments at 33; Grid United Initial Comments at 3; Policy Integrity Initial Comments at 27–28; US DOE Initial Comments at 31–32.

¹⁵²⁹ Clean Energy Associations Initial Comments at 19.

¹⁵³⁰ Breakthrough Energy Initial Comments at 22.

¹⁵³¹ Grid United Initial Comments at 3.

¹⁵³² Policy Integrity Initial Comments at 3, 27–28.

¹⁵³³ PJM Initial Comments at 93 (citing NOPR, 179 FERC ¶ 61,028 at P 186).

¹⁵³⁴ SREA Reply Comments at 26–27.

¹⁵³⁵ Enel Initial Comments at 3; Clean Energy Association Initial Comments at 20; Conservative Energy Network Supplemental Comments at 1; Conservatives for Clean Energy—Florida Supplemental Comments at 1; Conservatives for Clean Energy—South Carolina Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; Michigan Conservative Energy Forum Supplemental Comments at 1; Ohio Conservative Energy Forum Supplemental Comments at 1; Western Way Colorado Supplemental Comments at 1; Western Way Nevada Supplemental Comments at 1; Western Way Utah Supplemental Comments at 1; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

¹⁵³⁶ Enel Initial Comments at 3.

¹⁵³⁷ Anbaric Initial Comments at 6–7; RMI Initial Comments at 2.

¹⁵³⁸ Anbaric Initial Comments at 6–7.

¹⁵³⁹ RMI Initial Comments at 2.

¹⁵⁴⁰ AEE Initial Comments at 26.

¹⁵⁴¹ *Id.*

¹⁵⁴² Hannon Armstrong Initial Comments at 2–3.

¹⁵⁴³ ITC Initial Comments at 5, 18–22.

¹⁵⁴⁴ Southeast PIOs Initial Comments at 50.

¹⁵⁴⁵ *Id.* at 53.

¹⁵⁴⁶ Southeast PIOs Reply Comments at 28 (citing Southern Initial Comments at 25–26; SERTP Sponsors Initial Comments at 30).

¹⁵⁴⁷ GridLab Initial Comments at 25.

process regardless of where they are located.¹⁵⁴⁸

694. Tabors Caramanis Rudkevich states that when transmission planning analyses account for the benefits of capital cost savings, resource adequacy, and resilience, the total benefits of transmission infrastructure will exceed the cost.¹⁵⁴⁹ Tabors Caramanis Rudkevich provides an example of multi-value benefit stacking for the transmission line connecting ERCOT and Southern Company and states that the results show total benefits of \$390 million, compared to \$33 million when considering production cost savings alone.¹⁵⁵⁰

695. Certain TDUs and NESCOE support or are amenable to a requirement for minimum benefits that also allows for flexibility in determination of additional benefits.¹⁵⁵¹ Specifically, NESCOE recommends that the Commission establish a list of benefits that must be considered for a regional discussion on transmission cost allocation and that the benefits list in the NOPR is an appropriate starting point. However, NESCOE contends, after consulting with the states, transmission providers should have the flexibility to include additional benefits or remove benefits from the list, asserting that such an approach would help facilitate collaboration in determining the appropriate set of benefits for a transmission planning region.¹⁵⁵² NESCOE also argues that, because benefits and the methods of measuring them may change over time, the Commission should clarify in any final order that transmission providers may modify or add benefits in future FPA section 205 filings.¹⁵⁵³

696. Certain TDUs also urge the Commission to allow for regional flexibility and state involvement in determining other measurable and quantifiable benefits to use in evaluating Long-Term Regional Transmission Facilities.¹⁵⁵⁴ While arguing for requiring certain benefits, Cypress Creek states that it agrees with Brattle Group that requiring evaluation of all 12 benefits in every scenario would detract from necessary regional flexibility.¹⁵⁵⁵ Cypress Creek asserts that the

Commission should require two additional project/region-specific benefits in evaluating multi-value projects but does not explain what they should be.¹⁵⁵⁶

697. Exelon supports the Commission's proposal to provide flexibility to each transmission planning region to identify which benefits they will use in Long-Term Regional Transmission Planning. For instance, Exelon suggests that congestion reduction is more applicable to regions with Locational Marginal Price pricing, while it may be impossible to calculate the benefits of deferred generation capacity investments in a region like PJM where generation capacity is largely market-driven.¹⁵⁵⁷ Similarly, the New Jersey Commission recommends providing regional flexibility to include additional benefits that may be harder to quantify and/or do not reduce customers' bills (e.g., resilience benefits and the value of meeting state public policies).¹⁵⁵⁸

698. Clean Energy Buyers state that the proposed set of benefits is generally appropriate and that a common set of benefits would allow for the proper identification of benefits in Long-Term Regional Transmission Planning, accounting for changes in the resource mix and demand, and facilitating stakeholder participation. Therefore, Clean Energy Buyers argue, the Commission should require transmission providers to adopt a set of Commission-identified benefits that are consistent with the just and reasonable standard or demonstrate on compliance why they should not have to do so. That said, Clean Energy Buyers state that the Commission should permit transmission providers to propose processes for weighing benefits in accordance with their relative importance in each specific transmission planning region.¹⁵⁵⁹

699. Several commenters recognize that benefits analysis can be resource intensive and therefore recommend that the Commission allow transmission providers to use a screening approach that initially screens benefit categories for significance before investing staff resources and modeling work to provide a detailed quantification.¹⁵⁶⁰ Clean

Energy Buyers argue that, at a minimum, the Commission should require that transmission providers screen for all 12 benefits listed in the NOPR and quantify them accordingly.¹⁵⁶¹ Hannon Armstrong states that while certain benefits may have a zero or *de minimis* contribution for certain candidate transmission projects, the Commission should require transmission providers to document each potential benefit by using a high-level screening analysis or detailed modeling as applicable.¹⁵⁶² PIOs assert that screening tools can be used to reduce analytical burdens, allowing transmission providers to self-certify compliance and/or provide justifications for when benefits do not apply.¹⁵⁶³

i. List of Benefits Proposed in the NOPR

700. Some commenters support requiring transmission providers to consider all 12 illustrative benefits enumerated in the NOPR.¹⁵⁶⁴ ACORE contends that these categories represent a best practice and track closely with recommended multi-benefit planning approaches.¹⁵⁶⁵ Breakthrough Energy notes that some of the Commission-listed benefits can be very significant but are typically ignored in today's transmission planning processes.¹⁵⁶⁶ SEIA and Fervo assert that the final order should account for the full range of transmission benefits and use multi-value planning to comprehensively identify investments that address all categories of needs and benefits.¹⁵⁶⁷

701. PIOs state that there is strong evidence in the record to support the proposed list of benefits, including extensive testimony provided by the Brattle Group and others. PIOs state that these benefits all correlate with needs

¹⁵⁶¹ Clean Energy Buyers Initial Comments at 20–21.

¹⁵⁶² Hannon Armstrong Initial Comments at 2–3.

¹⁵⁶³ PIOs Initial Comments at 41.

¹⁵⁶⁴ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

¹⁵⁶⁵ ACORE Initial Comments at 12 (citing Rob Gramlich, Grid Strategies LLC, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis*, at 9 (Aug. 9, 2022)).

¹⁵⁶⁶ Breakthrough Energy Initial Comments at 22.

¹⁵⁶⁷ Fervo Reply Comments at 2; SEIA Initial Comments at 16.

¹⁵⁴⁸ Pattern Energy Reply Comments at 6–8 (citing ACEG Initial Comments at 32; Clean Energy Associations Initial Comments at 21).

¹⁵⁴⁹ Tabors Caramanis Rudkevich Initial Comments at 6.

¹⁵⁵⁰ *Id.*

¹⁵⁵¹ Certain TDUs Initial Comments at 2–3, 9–12; NESCOE Initial Comments at 43–44.

¹⁵⁵² NESCOE Initial Comments at 44.

¹⁵⁵³ *Id.* at 43–44.

¹⁵⁵⁴ Certain TDUs Initial Comments at 9.

¹⁵⁵⁵ Cypress Creek Reply Comments at 7–8 (citing PIOs Initial Comments Ex. A, ¶¶ 8–9).

¹⁵⁵⁶ *Id.* at 8.

¹⁵⁵⁷ Exelon Initial Comments at 15.

¹⁵⁵⁸ New Jersey Commission Initial Comments at 14.

¹⁵⁵⁹ Clean Energy Buyers Initial Comments at 19–21.

¹⁵⁶⁰ ACEG Initial Comments at 7, 33; ACORE Initial Comments at 12; Breakthrough Energy Initial Comments at 22; CTC Global Initial Comments at 9; Interwest Initial Comments at 12–13; WATT Coalition Initial Comments at 7.

and goals associated with Long-Term Regional Transmission Planning and, as such, the Commission should require transmission providers to consider them for most, if not all, regional transmission projects. Finally, PIOs encourage the Commission to make clear that these benefits should be assessed as part of any transmission planning process—even those conducted for economic purposes.¹⁵⁶⁸

702. Amazon supports the list of benefits set forth in the NOPR and urges the Commission to make consideration of those benefits mandatory except insofar as a transmission provider files for waiver and overcomes a strong presumption of their relevance to transmission planning and cost allocation.¹⁵⁶⁹ To facilitate the responsible construction of transmission facilities, ENGIE recommends that the Commission incorporate the 12 listed benefits as a minimum set of benefits for analysis but permit flexibility in how transmission providers conduct their analysis.¹⁵⁷⁰

ii. Application of the Benefits of Long-Term Regional Transmission Facilities in Non-RTO/ISO Regions

703. Certain commenters state that all or most of the Commission's proposed benefits are applicable and appropriate in non-RTO/ISO transmission planning regions.¹⁵⁷¹ For example, ACEG states the minimum set of benefits should be implemented as universally as possible across RTOs/ISOs and non-RTO/ISO regions.¹⁵⁷² PIOs state that the Brattle-Grid Strategies Oct. 2021 Report shows the numerous benefits not currently quantified in RTO/ISO regions to consumers' detriment and that the problem is more dire in non-RTO/ISO regions.¹⁵⁷³ Relatedly, MISO states that benefits could be applied in non-RTO/ISO regions but may be limited or not fully realized due to less coordinated congestion management and transmission planning.¹⁵⁷⁴

704. SEIA comments that the Commission should mandate the consideration of benefits of Long-Term Regional Transmission Facilities in non-RTO/ISO transmission planning regions. Otherwise, SEIA states, transmission providers could rely on state integrated resource planning processes, which do not incorporate lower cost transmission

alternatives to generation procurement, potentially leading to transmission expansion to accommodate higher-cost generation than is needed. According to SEIA, there is no basis to apply different benefits in non-RTO/ISO transmission planning regions, because many of the proposed benefits of Long-Term Regional Transmission Facilities have already been calculated in non-RTO/ISO regions.¹⁵⁷⁵

705. Southeast PIOs claim that Southeastern transmission providers should not be exempt from quantifying benefits, even if some benefits do not apply in the same manner to non-RTO/ISO transmission planning regions as they do to RTO/ISO regions.¹⁵⁷⁶ Southeast PIOs advocate for the Commission to establish standardized metrics for both RTO/ISO regions and non-RTO/ISO regions to capture similar benefits.¹⁵⁷⁷ Otherwise, Southeast PIOs argue, transmission providers will continue to focus only on costs, thereby depriving states and stakeholders of a fuller picture of transmission planning options.¹⁵⁷⁸ TAPS contends that no transmission facilities have been selected in a regional transmission plan for purposes of cost allocation since the implementation of Order No. 1000 in non-RTO/ISO transmission planning regions partly because of the narrow factors that most non-RTO/ISO regions consider in evaluating the benefits of potential transmission projects.¹⁵⁷⁹

706. Other commenters express concern that certain NOPR benefits would be inapplicable or problematic to apply to non-RTO/ISO transmission planning regions or argue that the same types of benefits should not be applied to both sets of regions.¹⁵⁸⁰ California Municipal Utilities oppose applying the list of benefits to non-RTO/ISO transmission planning regions, stating that doing so would misapprehend the state and local nature of resource portfolio planning and would fail to account for the costs of such prescriptive measures and to provide consumer protection measures to guard against speculative transmission projects.¹⁵⁸¹ Dominion states that a one-size-fits-all approach to benefits may be inappropriate, for instance, in locations

where some transmission providers operate outside of an RTO/ISO while others function within an RTO/ISO.¹⁵⁸²

707. EEI and Idaho Power state that non-RTO/ISO transmission planning regions may not be able to calculate reduced congestion or increased market liquidity.¹⁵⁸³ Likewise, North Carolina Commission and Staff state that some of the benefits proposed for consideration are only applicable in RTOs/ISOs (e.g., increased market liquidity) and argue that some benefits could conflict with state-jurisdictional resource decisions (e.g., production cost savings, access to lower-cost generation).¹⁵⁸⁴

708. Southern states that, while certain benefits identified in the NOPR could work for Southern's non-RTO/ISO footprint, others could harm underlying state integrated resource planning/request for proposal processes or are suited only for RTO/ISO markets, such as increased market liquidity.¹⁵⁸⁵ For example, Southern states that considering production cost savings effectively would make generation resource-related decisions that would intrude into integrated resource plan/request for proposal planning, which considers the total costs (including both generation and transmission costs) of available alternatives to customers.¹⁵⁸⁶ Similarly, SERTP Sponsors state that, because SERTP Sponsors continue to use integrated resource plan/request for proposal planning to make their resource and load determinations, some of the benefits that are appropriate for consideration in RTOs/ISOs are inapplicable for transmission planning or cost allocation purposes in the Southeast.¹⁵⁸⁷ SERTP Sponsors further state that, as the states have exclusive jurisdiction over such integrated resource plan/generation matters, requiring consideration of "[integrated resource plan/request for proposal]-related benefits," including production cost savings, capacity costs benefits, reduced planning reserve margins, and reduced peak energy losses, could exceed the Commission's jurisdiction by infringing on such state processes.¹⁵⁸⁸

709. Kentucky Commission Chair Chandler argues against SERTP Sponsors' comments that suggest that integrated resource plan/request for proposal processes already consider four of the proposed categories of

¹⁵⁷⁵ SEIA Initial Comments at 17–18.

¹⁵⁷⁶ Southeast PIOs Initial Comments at 51.

¹⁵⁷⁷ *Id.* at 52.

¹⁵⁷⁸ *Id.* at 52–53.

¹⁵⁷⁹ TAPS Initial Comments at 15.

¹⁵⁸⁰ California Municipal Utilities Reply Comments at 5–6; Dominion Reply Comments at 2; Duke Initial Comments at 23; EEI Initial Comments at 19; Idaho Power Initial Comments at 8; North Carolina Commission and Staff Initial Comments at 7; Southern Initial Comments at 25–27.

¹⁵⁸¹ California Municipal Utilities Reply Comments at 5–6.

¹⁵⁸² Dominion Reply Comments at 2.

¹⁵⁸³ EEI Initial Comments at 19; Idaho Power Initial Comments at 8.

¹⁵⁸⁴ North Carolina Commission and Staff Initial Comments at 7.

¹⁵⁸⁵ Southern Initial Comments at 25–27.

¹⁵⁸⁶ *Id.* at 26.

¹⁵⁸⁷ SERTP Sponsors Initial Comments at 30.

¹⁵⁸⁸ SERTP Sponsors Initial Comments at 30.

¹⁵⁶⁸ PIOs Initial Comments at 37–38, 41.

¹⁵⁶⁹ Amazon Initial Comments at 5.

¹⁵⁷⁰ ENGIE Reply Comments at 3.

¹⁵⁷¹ ACEG Initial Comments at 32, 48, 61; PIOs Initial Comments at 42; SEIA Initial Comments at 17.

¹⁵⁷² ACEG Initial Comments at 32.

¹⁵⁷³ PIOs Initial Comments at 42.

¹⁵⁷⁴ MISO Initial Comments at 51.

benefits included in the NOPR. Kentucky Commission Chair Chandler contends that the integrated resource planning/request for proposal process can only address these four categories on a utility-by-utility basis and, thus, is unable to plan for transmission facilities across utilities or transmission planning regions by nature.¹⁵⁸⁹

710. Some commenters advocate for or against requiring transmission providers to consider other specific lists, categories, or combinations of benefits, arguing that such approaches reduce possible duplication of benefits, increase flexibility, and/or focus on benefits they believe are most important.¹⁵⁹⁰ PIOs, for example, assert that some commenters who are opposed to the list of benefits in the NOPR nonetheless agree that transmission planners should quantify broad categories of benefits to plan effectively.¹⁵⁹¹ AEP states that some benefits are more difficult to calculate than others and argues that the minimum set of benefits it recommends appropriately balances the significance of each type of benefit with the difficulty of quantifying that benefit.¹⁵⁹²

711. AEP and GridLab argue that many of the benefits listed in the NOPR measure or identify the same type of benefit and therefore argue that the Commission should group similar benefits together into categories to avoid double-counting.¹⁵⁹³ Specifically, AEP and GridLab propose that the production cost savings and access to lower-cost generation benefits be grouped into a required category.¹⁵⁹⁴ In addition, AEP states that the reduced loss of load probability, reduced planning reserve margin, capacity cost benefits from reduced peak energy losses, and deferred capacity investments benefits should be combined into one required category.¹⁵⁹⁵

712. GridLab and PJM contend that the Commission should combine the benefits of reduced loss of load

probability and deferred generation capacity investment into a single category of benefits.¹⁵⁹⁶ PJM further argues that the Commission should combine the benefits of mitigation of extreme events and mitigation of weather and load uncertainty.¹⁵⁹⁷

713. California Commission recommends that to capture the benefits of transmission infrastructure, the Commission should require transmission providers to assess benefits within the following six benefit categories: (1) production cost benefits; (2) emissions reductions benefits; (3) generation capital cost benefits; (4) risk mitigation benefits; (5) resource adequacy benefits; and (6) resilience benefits. California Commission states that such a requirement would promote greater uniformity in how the benefits of regional (and interregional) transmission projects are evaluated, reducing potential disputes over cost allocation.¹⁵⁹⁸ However, California Commission argues, the Commission should allow transmission providers, in consultation with Relevant State Entities, to define each identified benefit and determine how to quantify it.¹⁵⁹⁹ To ensure that customers are protected from speculative transmission development and unreasonably high costs, California Commission concludes that the Commission should require transmission providers to demonstrate on compliance that they identified and defined benefits within each of the required benefit categories and determined appropriate quantification methods through a transparent public process.¹⁶⁰⁰

714. Joint Consumer Advocates state that the following categories of benefits should be included in Long-Term Regional Transmission Planning: (1) production cost savings; (2) avoided or deferred reliability transmission facilities; and (3) aging transmission infrastructure replacement.¹⁶⁰¹

715. AEE notes that some commenters propose that the Commission adopt a smaller set of benefit categories.¹⁶⁰² AEE states that while there may be value in considering these proposals, they miss important benefits such as increased competition, market liquidity, and

increased resilience from mitigation of extreme weather events effects and system contingencies.¹⁶⁰³ Thus, AEE recommends that the Commission adopt as mandatory the full set of 12 benefits listed in the NOPR but allow a transmission provider to demonstrate that an alternative set of benefits captures all the benefits of transmission in its transmission planning region.

716. A few commenters offer categories of benefits while noting the importance of regional flexibility.¹⁶⁰⁴ ACEG notes widespread support for the Commission to require certain categories of minimum benefits and requests flexibility for transmission providers to address these categories in accordance with regional needs. ACEG states that considering categories of benefits will reduce the risk of double-counting or miscalculating benefits and allow flexibility to apply specific benefits best suited to each transmission planning region.¹⁶⁰⁵

717. In addition to concerns expressed by commenters in the context of the combinations of benefits proposed above, other commenters express concern regarding the potential for double-counting of benefits if transmission providers are required to consider certain benefits.¹⁶⁰⁶ For example, NRECA asserts that accounting for increased competition and increased market liquidity would risk double-counting benefits,¹⁶⁰⁷ and Utah Division of Public Utilities argues that accounting for both reduction in loss of load probability and mitigation of extreme events and system contingencies would result in double-counting.¹⁶⁰⁸ Clean Energy Buyers ask that the Commission require transmission providers to explain how they will avoid double-counting issues,¹⁶⁰⁹ while ISO-NE seeks more information from the Commission regarding which benefits the Commission believes are redundant.¹⁶¹⁰

¹⁶⁰³ *Id.*

¹⁶⁰⁴ ACEG Reply Comments at 6–7; Entergy Initial Comments at 21.

¹⁶⁰⁵ ACEG Reply Comments at 6–7 (citing Entergy Initial Comments at 21; AEP Initial Comments at 23–27; Exelon Initial Comments at 15–16).

¹⁶⁰⁶ *See, e.g.,* APPA Initial Comments at 32; City of New Orleans Council Initial Comments at 10–11; Louisiana Commission Reply Comments at 10; Michigan Commission Initial Comments at 6; Nevada Commission Initial Comments at 10–11; Utah Division of Public Utilities Initial Comments at 8; Vistra Initial Comments at 16–17.

¹⁶⁰⁷ NRECA Initial Comments at 45 (citing NRECA Initial Comments, attach. at 16–17).

¹⁶⁰⁸ Utah Division of Public Utilities Initial Comments at 8.

¹⁶⁰⁹ Clean Energy Buyers Initial Comments at 20–21.

¹⁶¹⁰ ISO-NE Initial Comments at 34.

¹⁵⁸⁹ Kentucky Commission Chair Chandler Reply Comments at 7.

¹⁵⁹⁰ ACEG Reply Comments at 6–7; AEE Reply Comments at 25–26; AEP Initial Comments at 6, 23–25; California Commission Initial Comments at 31–34; Certain TDUs Reply Comments at 1–2; Entergy Initial Comments at 21; GridLab Initial Comments at 27; Joint Consumer Advocates Initial Comments at 11; PIOs Reply Comments at 7–9; PJM Initial Comments at 94–96; PPL Initial Comments at 14.

¹⁵⁹¹ PIOs Reply Comments at 7–8 (citing Entergy Initial Comments at 21; Exelon Initial Comments at 15).

¹⁵⁹² AEP Initial Comments at 23.

¹⁵⁹³ AEP Initial Comments at 23–24; GridLab Initial Comments at 27.

¹⁵⁹⁴ AEP Initial Comments at 25; GridLab Initial Comments at 27.

¹⁵⁹⁵ AEP Initial Comments at 25.

¹⁵⁹⁶ GridLab Initial Comments at 27; PJM Initial Comments at 95.

¹⁵⁹⁷ PJM Initial Comments at 94.

¹⁵⁹⁸ California Commission Initial Comments at 33.

¹⁵⁹⁹ *Id.* at 28–29.

¹⁶⁰⁰ *Id.* at 34–35.

¹⁶⁰¹ Joint Consumer Advocates Initial Comments at 11.

¹⁶⁰² AEE Reply Comments at 25–26 (citing PJM Initial Comments at 93–96; California Commission Initial Comments at 32; New Jersey Commission Initial Comments at 13–14).

718. A few commenters state that the list of 12 benefits in the NOPR does not risk double-counting.¹⁶¹¹ DC and MD Offices of People's Counsel concludes that each benefit in this list is mutually exclusive, noting that some transmission providers may wish to mix and match these benefits because their modeling tools may not disaggregate them in exactly the way described in the NOPR.¹⁶¹² MISO notes that there are instances where one benefit can enable other benefits and that adopting a calculation method that recognizes that complementary behavior can yield incremental value.¹⁶¹³ For example, MISO states, a calculation approach that distinguishes between the benefit of enabling resource expansion and the benefit of increased transmission capability provided by regional transmission projects would produce unique benefits.¹⁶¹⁴

c. Commission Determination

719. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure a set of seven required benefits (required benefits) for Long-Term Regional Transmission Facilities under each Long-Term Scenario as part of Long-Term Regional Transmission Planning. Furthermore, we adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to use these measured benefits to evaluate Long-Term Regional Transmission Facilities, as discussed below in the Evaluation and Selection of Regional Transmission Facilities section. This Evaluation of the Benefits of Regional Transmission Facilities section discusses this final order's requirements with regard to transmission providers' measurement and use of benefits in evaluating Long-Term Regional Transmission Facilities; however, as discussed in the Development of Long-Term Scenarios section, these same benefits should help to inform transmission providers' identification of Long-Term Transmission Needs.¹⁶¹⁵

720. The seven required benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning, which we

describe in greater detail in the discussion of the individual benefits below, are: (1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme weather events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses.¹⁶¹⁶

721. We find that these requirements are necessary to ensure that transmission providers can evaluate Long-Term Regional Transmission Facilities to determine whether they more efficiently or cost-effectively address Long-Term Transmission Needs. Specifically, we find that transmission providers must measure these seven required benefits in each Long-Term Scenario because, as discussed further in the Evaluation and Selection of Regional Transmission Facilities section, evaluating Long-Term Regional Transmission Facilities for potential selection necessarily involves the consideration of the benefits measured in each Long-Term Scenario and sensitivity to help address uncertainty over the 20-year transmission planning horizon and to maximize benefits accounting for costs over time. As such, we find that, to ensure just and reasonable Commission-jurisdictional rates, transmission providers must measure, at minimum, the set of seven required benefits in Long-Term Regional Transmission Planning and then use them to evaluate Long-Term Regional Transmission Facilities for selection.

722. Although the Commission did not propose to require the use of any specific benefits in the NOPR, the Commission sought comment on whether it should require transmission providers to use some or all of the potential benefits described in the NOPR as a minimum set of benefits in Long-Term Regional Transmission Planning. The record in this proceeding shows that, in order to ensure just and reasonable Commission-jurisdictional transmission rates, it is necessary to require transmission providers to measure and use in Long-Term Regional Transmission Planning a set of particular benefits so that they may identify, evaluate, and select regional

transmission facilities that are more efficient or cost-effective transmission solutions to Long-Term Transmission Needs. We find that the benefits that Long-Term Regional Transmission Facilities generally provide extend beyond the benefits that transmission providers currently consider as part of their regional transmission planning and cost allocation processes, and without consideration of such benefits, Long-Term Regional Transmission Planning cannot be reasonably expected to identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

723. By requiring the measurement and use of the seven enumerated benefits in Long-Term Regional Transmission Planning, we ensure that transmission providers will consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. In contrast, adopting the more flexible approach proposed in the NOPR would not address the identified deficiencies in existing regional transmission planning and cost allocation processes because such an approach would fail to ensure that transmission providers consider the broader set of benefits provided by, and the beneficiaries receiving the benefits of, Long-Term Regional Transmission Facilities, and thus, may fail to identify the potentially more efficient or cost-effective regional transmission solution. We find that failing to use the set of benefits that we require in this final order to evaluate Long-Term Regional Transmission Facilities for potential selection could render resulting Commission-jurisdictional rates unjust and unreasonable. We find that not requiring transmission providers to use certain benefits to evaluate Long-Term Regional Transmission Facilities would be expected to lead to relatively inefficient and less cost-effective transmission development, as Long-Term Regional Transmission Facilities that provide significant net benefits may not be selected.¹⁶¹⁷ In addition, we find that the transparency provided by requiring consideration of a sufficiently broad and common set of benefits will help to ensure the costs of Long-Term Regional Transmission Facilities are allocated to beneficiaries in a manner that is at least

¹⁶¹¹ DC and MD Offices of People's Counsel Initial Comments at 20; MISO Initial Comments at 50.

¹⁶¹² DC and MD Offices of People's Counsel Initial Comments at 20.

¹⁶¹³ MISO Initial Comments at 50.

¹⁶¹⁴ *Id.*

¹⁶¹⁵ See *supra* Long-Term Regional Transmission Planning, Development of Long-Term Scenarios section.

¹⁶¹⁶ We discuss modifications to Benefit 6 from its description in the NOPR in the Benefit 6 determination section.

¹⁶¹⁷ See Clean Energy Associations Initial Comments at 20 (citing The Brattle Group, *Transmission Planning and Benefit-Cost Analyses*, at 26 (Apr. 2021)).

roughly commensurate with the benefits they derive from them.¹⁶¹⁸

724. We appreciate arguments made by certain commenters that failure to incorporate identifiable benefits risks skewing the evaluation process against developing needed and beneficial Long-Term Regional Transmission Facilities because transmission providers would consider all of the costs of such transmission facilities without similarly considering many important benefits that they may provide.¹⁶¹⁹ However, we are also cognizant of concerns about duplication of benefits and difficulty of measuring certain benefits. In this final order, rather than requiring transmission providers to measure and use all 12 benefits enumerated in the NOPR, we only require transmission providers to measure and use seven specific benefits that have a proven track record, can be discretely measured, and are unlikely to cause duplication. We find that the modification to the NOPR proposal to require the measurement and use of these seven benefits to evaluate Long-Term Regional Transmission Facilities, as discussed above, resolves concerns about important benefits being omitted from Long-Term Regional Transmission Planning, as well as challenges raised concerning duplication and measurement of certain benefits.

725. We acknowledge that many commenters do not favor requiring the use of particular benefits. In response, we emphasize that a set of common benefits and a requirement to measure and use those benefits in Long-Term Regional Transmission Planning will ensure just and reasonable rates, as discussed above.¹⁶²⁰ Specifically, unless

transmission providers consider a sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs, they may fail to identify the more efficient or cost-effective regional transmission solution, resulting in relatively inefficient or less cost-effective transmission development.

726. We note that some commenters request flexibility to use different benefits, such as SPP, which states that the effort required to incorporate additional benefit metrics into its current regional transmission planning process cannot be accommodated within its current process timeline.¹⁶²¹ As discussed in the Implementation and Compliance sections of this final order, we require transmission providers to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final order are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles), and thus transmission providers will not be required to immediately implement this reform.

727. Some commenters argue that the requirement to measure and use these benefits will increase costs and require additional effort, and that the Commission has presented insufficient evidence that this requirement will produce the desired benefits.¹⁶²² Commenters who express such concerns did not provide persuasive evidence to suggest that requiring the measurement and use of a required set of benefits would be unduly burdensome. While measuring these benefits may impose a degree of burden on some transmission providers, the requirement for

transmission providers to measure and use the seven required benefits in Long-Term Regional Transmission Planning is necessary to ensure that rates are just and reasonable. Specifically, absent a requirement that transmission providers measure and use a sufficiently broad range of benefits of Long-Term Regional Transmission Facilities when evaluating them for potential selection, transmission providers may not identify, evaluate, and select more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs, which may lead to relatively inefficient or less cost-effective transmission development. Further, we believe that experience gained by transmission providers will over time allow them to perform the necessary measurements more efficiently. Moreover, in our discussion of each required benefit below, we provide a description, for several of the required benefits, of at least one manner in which transmission providers could measure each required benefit. Finally, commenters also did not provide persuasive evidence that the burdens of measuring and using a required set of benefits outweigh the benefits of using these benefits in Long-Term Regional Transmission Planning. We therefore find that any burdens of measuring and using the seven required benefits in Long-Term Regional Transmission Planning are outweighed by the identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs.¹⁶²³

728. Another common concern expressed by some commenters is that requiring a minimum set of benefits would undermine regional flexibility.¹⁶²⁴ We conclude that it would be inappropriate to provide flexibility not to consider this required set of benefits in Long-Term Regional Transmission Planning because, as described above, requiring the measurement and use of these benefits ensures that transmission providers are able to identify, evaluate, and select regional transmission solutions to more efficiently or cost-effectively address Long-Term Transmission Needs, and thereby ensures just and reasonable rates. We therefore disagree with Dominion that transmission providers should be permitted to identify initial benefits that they will consider in

¹⁶¹⁸ *ICC v. FERC I*, 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639 (requiring costs of regional transmission facilities to be allocated in a manner that is at least roughly commensurate with estimated benefits).

¹⁶¹⁹ See Enel Initial Comments at 3.

¹⁶²⁰ See ACORE Initial Comments at 12; ACORE Reply Comments at 6; ACORE Supplemental Comments at 1; AEE Initial Comments at 8, 25; AEP Initial Comments at 6, 23–25; Breakthrough Energy Initial Comments at 4, 21–22; Business Council for Sustainable Energy Initial Comments at 2, 5; Certain TDUs Initial Comments at 11–12; Clean Energy Buyers Reply Comments at 8–9; Concerned Scientists Reply Comments at 7–10; Cypress Creek Reply Comments at 7–8; DC and MD Offices of People's Counsels Reply Comments at 3, 7–8; ELCON Initial Comments at 15; Enel Initial Comments at 3; Environmental Groups Supplemental Comments at 2; Environmental Legislators Caucus Supplemental Comments at 1; Exelon Initial Comments at 16; Grid United Initial Comments at 2; Handy Law Initial Comments at 8; US House Republicans Supplemental Comments at 1; Indicated US Senators and Representatives Initial Comments at 2; ITC Initial Comments at 5, 18–22; Interwest Initial Comments at 12; Interwest Reply Comments at 6–7; Joint Consumer Advocates Initial Comments at 11; Kentucky Commission Chair

Chandler Reply Comments at 7; Minnesota State Entities Initial Comments at 6; New England for Offshore Wind Initial Comments at 5; New Jersey Commission Initial Comments at 11–14; Pacific Northwest State Agencies Initial Comments at 16–17; PIOs Initial Comments at 27–28; PIOs Reply Comments at 7–8; Policy Integrity Initial Comments at 27; Policy Integrity Supplemental Comments at 4; R Street Initial Comments at 9; RMI Initial Comments at 1; RMI Supplemental Comments at 2; SEIA Initial Comments at 16–17; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27–28; ; US DOE Initial Comments at 30–33; US Senator Schumer Supplemental Comments at 1–2; US Senator Whitehouse Supplemental Comments at 2; US Senators Supplemental Comments at 2; WATT Coalition Initial Comments at 7.

¹⁶²¹ SPP Initial Comments at 18.

¹⁶²² E.g., Dominion Initial Comments at 34–35.

¹⁶²³ See Clean Energy Associations Initial Comments at 20 (“Not requiring benefits to be evaluated could lead to higher costs in the long-term, and, thus, unjust and unreasonable rates.”).

¹⁶²⁴ E.g., Entergy Initial Comments at 21.

conducting Long-Term Regional Transmission Planning but retain flexibility in applying such benefits to each transmission provider's individual circumstances.¹⁶²⁵ However, as we discuss further below, we are providing flexibility to transmission providers regarding how they will measure each of the required benefits.

729. Transmission providers may also propose to measure and use additional benefits in Long-Term Regional Transmission Planning, as discussed below in the Other Benefits section. This approach provides flexibility to transmission providers in how they implement the requirement to measure and use the required set of benefits in Long-Term Regional Transmission Planning, while maintaining the baseline requirement that they measure and use all seven benefits included in that required set of benefits, in order to ensure that rates remain just and reasonable. Requiring all transmission providers to measure and use a required set of benefits will help to improve interregional transmission coordination among different transmission planning regions, as noted by commenters.¹⁶²⁶

730. In addition, as more fully described below, we also find that the seven benefits we require are not overly burdensome to calculate. We address such concerns for individual benefits in more detail within the determination section on each benefit below.

731. Some commenters assert that some benefits are only appropriate for use in RTO/ISO transmission planning regions.¹⁶²⁷ We believe that all seven required benefits can be calculated in both RTO/ISO and non-RTO/ISO transmission planning regions, as noted by ACEG.¹⁶²⁸ In particular, we note that all seven required benefits have either been approved for use in regional transmission planning in at least one non-RTO/ISO transmission planning region or may be implemented by building upon the modeling or techniques used to measure benefits in RTO/ISO or non-RTO/ISO regions, or both.

732. As described below, in the NOPR, the Commission noted that it approved the use of production cost savings (*i.e.*, Benefit 3) to evaluate Order No. 1000 economic transmission

projects in a non-RTO/ISO transmission planning region.¹⁶²⁹ We note that, as measurements of reduced production costs outside of normal conditions, the measurement methods for Benefit 5, Reduced Congestion Due to Transmission Outages, and Benefit 6, Mitigation of Extreme Weather Events and Unexpected System Conditions, may be built upon the modeling used to measure Benefit 3. Separately, the Commission has accepted use of benefits in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 2(a), Reduced Loss of Load Probability,¹⁶³⁰ and Benefit 4, Reduced Transmission Energy Losses, in non-RTO/ISO transmission planning regions.¹⁶³¹ In the NOPR, the Commission likewise noted that it has accepted accounting for the avoided costs (*i.e.*, Benefit 1) as part of a method for identifying beneficiaries and allocating costs in almost all the regional cost allocation methods in non-RTO/ISO transmission planning regions.¹⁶³² With respect to Final Order Benefit 7 (*i.e.*, capacity cost benefits from reduced peak energy losses), the avoided costs associated with this benefit are comparable across RTO/ISO and non-RTO/ISO transmission planning regions. Transmission providers in all transmission planning regions incur capital costs to meet installed generation requirements and to maintain reliable operations. Transmission expansions may help reduce peak energy losses, and under this benefit, result in capital cost savings associated with the reduction in installed generation requirements.

733. We disagree with commenters that express concerns that required benefits would conflict with state-regulated integrated resource planning processes.¹⁶³³ As discussed in the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section, nothing in this final order infringes on the states' reserved authority under FPA section 201.

734. Entergy argues that the Commission should recognize that not all benefits are created equal for all jurisdictions and that some states will

want transmission projects that actually reduce customer bills to have clear priority.¹⁶³⁴ We believe that the required measurement and use of the required set of benefits can accommodate such preferences. Our requirements ensure that all benefits are measured transparently and considered in selection decisions. In addition, our required set of benefits captures considerations such as production cost savings that can flow through to customer bills. PJM, for example, notes that lower production costs will generally also reduce market prices for electricity as lower-cost suppliers will set market clearing prices more frequently than without the transmission project.¹⁶³⁵ We note that while this final order requires the measurement and use of the required set of benefits, it is the evaluation process, including selection criteria, that transmission providers propose on compliance that will inform which Long-Term Regional Transmission Facilities are selected. Transmission providers may propose an evaluation process, including selection criteria, that reflect regional preferences as long as those criteria meet the requirements set forth below in the Evaluation and Selection of Long-Term Regional Transmission Facilities section.

735. ISO-NE notes that the Commission sought information on potential double-counting of benefits and requests that the Commission clarify which benefits the Commission believes are redundant.¹⁶³⁶ We believe that the seven benefits that we include in the required set of benefits that transmission providers must measure and use in Long-Term Regional Transmission Planning are distinct enough that they will not overlap in a way that results in double-counting. Nonetheless, to the extent that transmission providers are concerned that any possibility of double-counting remains, we provide transmission providers with flexibility on the measurement of such benefits and expect that transmission providers can use such flexibility to develop methods for measuring each required benefit that address those concerns.

736. Some commenters urge the Commission to adopt a combination or categorical approach toward benefits, under which required benefits would be grouped under certain categories or combinations.¹⁶³⁷ We decline to adopt

¹⁶²⁵ Dominion Initial Comments at 34.

¹⁶²⁶ Breakthrough Energy Initial Comments at 22–23; California Commission Initial Comments at 33; Grid United Initial Comments at 3; Policy Integrity Initial Comments at 27–28; US DOE Initial Comments at 31–32.

¹⁶²⁷ Pacific Northwest Utilities Initial Comments at 8–10; SERTP Sponsors Initial Comments 29–30; Southern Initial Comments at 25–27.

¹⁶²⁸ ACEG Initial Comments at 48.

¹⁶²⁹ NOPR, 179 FERC ¶ 61,028 at P 201 (citing *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206, at P 314 (2013)).

¹⁶³⁰ *PacifiCorp*, 147 FERC ¶ 61,057, at PP 133–134, 141–143 (2014); *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206 at P 314.

¹⁶³¹ *PacifiCorp*, 147 FERC ¶ 61,057 at PP 132, 134, 141–143.

¹⁶³² NOPR, 179 FERC ¶ 61,028 at PP 189–190 & n.326 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 81).

¹⁶³³ SERTP Sponsors Initial Comments at 30; Southern Initial Comments at 24–26.

¹⁶³⁴ Entergy Initial Comments at 21.

¹⁶³⁵ PJM Initial Comments at 95.

¹⁶³⁶ ISO-NE Initial Comments at 34.

¹⁶³⁷ ACEG Reply Comments at 6–7; AEP Initial Comments at 23–25; California Commission Initial

this approach, largely because our analysis and review of the record suggests that such an approach could reduce transparency regarding the benefits that we are requiring. For example, in some cases adopting a combination or categories approach could obfuscate individual benefit calculations within a category, making it less clear to interested parties what specific benefits a Long-Term Regional Transmission Facility may provide. Additionally, we find that these seven benefits merit individual measurement and evaluation.

737. Northwest and Intermountain and NYISO ask that the final order confirm that the 12 illustrative benefits described in the NOPR are not exhaustive.¹⁶³⁸ First, we confirm that the list of 12 illustrative benefits described in the NOPR is not an exhaustive list of the potential benefits of Long-Term Regional Transmission Facilities. Second, we reiterate that the required set of benefits adopted in this final order is a subset of the benefits listed in the NOPR, as modified in the discussions below. Transmission providers may be aware of additional benefits beyond those included in the required set of benefits, or the 12 illustrative benefits described in the NOPR, and we provide them with the flexibility to propose to measure and use additional benefits in Long-Term Regional Transmission Planning so long as they do so in a manner that is consistent with transmission providers' obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes. In particular, the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected to address Long-Term Transmission Needs.¹⁶³⁹ This necessarily means that stakeholders must understand which benefits transmission providers considered in the evaluation process, including any beyond the seven benefits that we require transmission providers to include in their OATTs. We find that this transparency strikes an appropriate balance between ensuring that

transmission providers measure and use the seven required benefits in Long-Term Regional Transmission Planning and allowing flexibility for transmission providers to use additional benefits that they believe will reasonably reflect the benefits of a Long-Term Regional Transmission Facility or Facilities in their transmission planning regions.

738. OMS urges the Commission to clarify that transmission providers will have sufficient flexibility to use different sets of benefit metrics in different transmission planning cycles.¹⁶⁴⁰ We clarify that transmission providers must use the required set of benefits to evaluate Long-Term Regional Transmission Facilities in every Long-Term Regional Transmission Planning cycle, and we discuss the use of other benefits to evaluate Long-Term Regional Transmission Facilities in the Other Benefits section of this final order.

739. Some commenters suggest that the Commission allow transmission providers to use a screening approach that initially screens benefit categories for significance before investing staff resources and modeling work to provide a detailed quantification.¹⁶⁴¹ Clean Energy Buyers similarly argue that, at a minimum, the Commission should require that transmission providers screen for all 12 benefits described in the NOPR and quantify them accordingly.¹⁶⁴² We find such screening approaches, as advocated by some commenters, to be inconsistent with the approach we adopt in this final order, which requires measurement and use of each of the seven required benefits in Long-Term Regional Transmission Planning, and we are concerned that permitting the use of screens could undermine this requirement. We therefore do not allow transmission providers to use a screening approach when measuring the seven required benefits.

2. Required Benefits

a. The Seven Required Benefits

i. Benefit 1: Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement

(a) NOPR Description

740. The Commission described this benefit in the NOPR as the reduced costs of avoided or delayed transmission

investment otherwise required to address reliability needs or replace aging transmission facilities. The Commission stated that, recognizing that regional transmission planning could lead to the development of transmission facilities that span the service territories of multiple transmission providers, which in turn would obviate the need for transmission facilities that would otherwise be identified in multiple local transmission plans, the Commission has accepted accounting for such "avoided costs" as part of a method for identifying beneficiaries and allocating costs in almost all the regional cost allocation methods in non-RTO/ISO regions.¹⁶⁴³ The Commission noted that, in using this method, transmission providers in a transmission planning region determine the beneficiaries of a regional transmission facility or portfolio of facilities by identifying the local and regional transmission facilities that a new proposed regional transmission facility or portfolio of facilities would displace. The Commission described the method as defining the benefits of the regional transmission facility or facilities as the costs that transmission providers in the transmission planning region "avoid" because they no longer need to build the displaced local and regional transmission facilities. Further, the Commission stated that the method allocates costs among transmission providers whose local or regional transmission facilities the new proposed regional transmission facility or facilities would displace in proportion to their share of the total benefits (*i.e.*, the total avoided costs). If the new proposed regional transmission facility or facilities do not displace any local or regional transmission facilities in existing local or regional transmission plans, the Commission discussed that the avoided cost method determines the benefits of the applicable facilities by considering the costs of local or regional transmission facilities that would otherwise be needed to meet the same need that the new proposed regional transmission facility will meet.¹⁶⁴⁴ The Commission noted that, in calculating this benefit, transmission providers in each transmission planning region could first identify transmission facilities that could defer or replace an identified reliability transmission solution. Avoided cost benefits could be calculated by comparing the cost of

Comments at 33; Entergy Initial Comments at 21; GridLab Initial Comments at 27; Joint Consumer Advocates Initial Comments at 11; PJM Initial Comments at 94–96.

¹⁶³⁸ Northwest and Intermountain Initial Comments at 16; NYISO Initial Comments at 39.

¹⁶³⁹ See *infra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

¹⁶⁴⁰ OMS Initial Comments at 8.

¹⁶⁴¹ ACEG Initial Comments at 7, 33; ACORE Initial Comments at 12; Breakthrough Energy Initial Comments at 22; CTC Global Initial Comments at 9; Interwest Initial Comments at 12–13; WATT Coalition Initial Comments at 7.

¹⁶⁴² Clean Energy Buyers Initial Comments at 20–21.

¹⁶⁴³ NOPR, 179 FERC ¶ 61,028 at PP 189–190 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 81).

¹⁶⁴⁴ NOPR, 179 FERC ¶ 61,028 at P 190 (citing *S.C. Elec. & Gas Co.*, 143 FERC ¶ 61,058, at P 232 (2013)).

transmission facilities required to address the reliability need without the proposed regional transmission facility to the cost of transmission facilities needed to address the reliability need assuming the regional transmission solution were in place.¹⁶⁴⁵

741. The Commission noted that Benefit 1 could also include the separate benefits stream caused by a deferral of replacement of other transmission facilities through identification and selection of a transmission facility or facilities. This could be measured through calculation of the present value savings for the period of deferral of additional replacement transmission facilities multiplied by their estimated capital cost.¹⁶⁴⁶ The Commission also noted that a number of transmission providers already evaluate the avoided or deferred costs of reliability transmission projects. For example, SPP uses a power flow model to analyze the ability of potential economic and Public Policy Requirements transmission facilities to meet the same thermal reliability needs addressed by a potential reliability transmission facility. The costs of these avoided or delayed reliability transmission facilities are used to determine the reliability benefit of the potential economic or Public Policy Requirements transmission facilities.¹⁶⁴⁷ The Commission stated that transmission providers could also use avoided costs to calculate the benefits of replacing aging transmission facilities. The Commission provided NYISO as an example, which estimates the benefits associated with the replacement of aging transmission facilities by quantifying the savings of not having to refurbish the facilities in the future.¹⁶⁴⁸

(b) Comments

742. A number of commenters support mandating consideration of Benefit 1.¹⁶⁴⁹ ACEG, for example,

¹⁶⁴⁵ *Id.* P 191 (citing Brattle-Grid Strategies Oct. 2021 Report at 37).

¹⁶⁴⁶ *Id.* P 192.

¹⁶⁴⁷ *Id.* P 193 (citing SPP, *SPP Benefit Metrics Manual*, SPP Engineering, at 15 (Nov. 6, 2020)).

¹⁶⁴⁸ *Id.* P 193 (citing The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, at 114 (Sept. 15, 2015)).

¹⁶⁴⁹ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25 (including Benefit 1 in its recommended minimum set of benefit categories); Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Certain TDUs Reply Comments at 1–2; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations

supports inclusion of this benefit, asserting that reliability considerations and replacing aging assets are responsible for almost all current transmission spending.¹⁶⁵⁰ However, MISO states that, when capturing avoided transmission investment benefits, care must be exercised to avoid the counting of benefits associated with facility overloads that are identified in reliability studies and directly addressed by regional transmission projects. MISO indicates that this approach is necessary because the adjusted production cost savings benefits already reflect the congestion associated with these facility overloads.¹⁶⁵¹ Southern states that this benefit would likely prove workable under its non-RTO/ISO construct because SERTP Sponsors' regional and interregional transmission planning and cost allocation processes already incorporate the benefit of "avoided costs."¹⁶⁵²

743. Several commenters oppose or express concerns with mandating consideration of Benefit 1.¹⁶⁵³ West Virginia Commission argues that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.¹⁶⁵⁴ Xcel states that benefit calculations can be different between the short-term regional transmission planning process and Long-Term Regional Transmission Planning and that, for example, it would likely be unreasonable to determine reliability benefits in Long-Term Regional Transmission Planning using the avoided cost of local reliability solutions.¹⁶⁵⁵

744. NARUC states that, while Benefit 1 seems capable of calculation, it carries with it a degree of risk if aging transmission infrastructure continues to be operated. For instance, NARUC indicates that some wildfires have been linked to deferred transmission maintenance of aging infrastructure.¹⁶⁵⁶ AEE responds by stating that the

Initial Comments at 1; New Jersey Commission Initial Comments at 11–13; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; PJM Initial Comments at 96; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

¹⁶⁵⁰ ACEG Initial Comments at 34–35.

¹⁶⁵¹ MISO Initial Comments at 50.

¹⁶⁵² Southern Initial Comments at 25.

¹⁶⁵³ Joint Consumer Advocates Initial Comments at 11; NARUC Initial Comments at 22; West Virginia Commission Supplemental Comments at 4; Xcel Initial Comments at 13.

¹⁶⁵⁴ West Virginia Commission Supplemental Comments at 4.

¹⁶⁵⁵ Xcel Initial Comments at 13.

¹⁶⁵⁶ NARUC Initial Comments at 22.

Commission should clarify: (1) its expectations regarding its calculation; and (2) that regional transmission built for inherently economic or public policy purposes has, when installed, avoided reliability cost benefits.¹⁶⁵⁷ AEE argues that calculating the benefits of avoided investment in reliability or replacement facilities should not create an environment for continuously putting "band aid" fixes on aging systems that should instead be replaced to ensure reliability and resilience.¹⁶⁵⁸

(c) Commission Determination

745. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 1, Avoided or Deferred Reliability Transmission Facilities and Aging Transmission Infrastructure Replacement, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 1 as the reduced costs due to avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities. We find that requiring the measurement and use of Benefit 1, as described, is necessary because Long-Term Regional Transmission Facilities may obviate or delay the need for reliability transmission facilities identified in the near term, or the need for later replacements of aging transmission infrastructure. Requiring transmission providers to measure and use the benefits associated with avoiding or delaying such transmission needs will help to ensure that, when conducting Long-Term Regional Transmission Planning, transmission providers identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

746. We note that a number of transmission providers already evaluate avoided or deferred costs of reliability transmission facilities. ACEG states that Benefit 1 reflects that reliability considerations and replacing aging assets drive significant investment in transmission and account for almost all current transmission spending.¹⁶⁵⁹ SPP employs a power flow model to analyze the ability of potential economic and Public Policy Requirements transmission facilities to meet the same thermal reliability needs addressed by a

¹⁶⁵⁷ AEE Reply Comments at 26 (citing NARUC Initial Comments at 22).

¹⁶⁵⁸ *Id.*

¹⁶⁵⁹ ACEG Initial Comments at 34–35.

potential reliability transmission facility, using the costs of these avoided or delayed reliability transmission facilities to determine the reliability benefit of the potential economic or Public Policy Requirements transmission facilities.¹⁶⁶⁰ Additionally, NYISO estimates the benefits associated with the replacement of aging transmission facilities by quantifying the savings of not having to refurbish the facilities in the future.¹⁶⁶¹ We find that widespread use of this benefit contradicts West Virginia Commission's assertion that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance, as well as similar assertions by Xcel.¹⁶⁶²

747. We agree with NARUC and AEE that continued operation of aging infrastructure can carry risks if it is not properly maintained.¹⁶⁶³ We note that nothing in this final order restricts an incumbent transmission provider from developing a local transmission facility to meet its reliability needs or service obligations in its own retail distribution service territory or footprint.¹⁶⁶⁴ Such a solution would not be subject to approval at the regional or interregional level where the transmission provider does not seek to have it selected as a regional transmission facility for purposes of cost allocation.¹⁶⁶⁵ Moreover, nothing in this final order requires transmission providers to keep transmission facilities in operation beyond their useful life. We emphasize that transmission providers can use Benefit 1 to calculate the costs that are avoided because replacements of local or regional transmission facilities are no longer needed, or may be deferred, when they are displaced by proposed new Long-Term Regional Transmission Facilities.

ii. Benefit 2(a): Reduced Loss of Load Probability or Benefit 2(b): Reduced Planning Reserve Margin

(a) NOPR Description

748. The Commission described this benefit in the NOPR as being measured in one of two ways: (a) using reduced loss of load probability or (b) reduced

planning reserve margin. The Commission noted that, because there is an overlap between reduced loss of load probability benefits and reduced planning reserve margin benefits, a single transmission facility can either reduce loss of load events if the planning reserve margin is unchanged or allow for the reduction in planning reserve margins if loss of load events remain constant, but not both simultaneously.¹⁶⁶⁶

749. The Commission described Benefit 2(a) in the NOPR as reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages (if the planning reserve margin is not changed despite lower loss of load events), as well as improved physical reliability benefits by reducing the likelihood of load shed events.¹⁶⁶⁷ The Commission noted that transmission investments, even those not made to satisfy a reliability need, generally enhance the reliability of the transmission system by increasing transfer capability, which, in turn, reduces the likelihood that a transmission provider will be unable to serve its load due to a shortage of generation over a given period. This enhancement in reliability can be measured as a reduction in loss of load probability, or the likelihood of system demand exceeding generation over a given period. The Commission noted that one example of how a reduction of loss of load probability benefit could be calculated can be found in a report by SPP's Metrics Task Force. The report proposes quantifying the incremental increase in system reliability by determining the reduction in expected unserved energy between the base case and the change case, obtaining the value of lost load, and multiplying these two values to obtain the monetary benefit of enhanced reliability associated with a transmission expansion.¹⁶⁶⁸

750. The Commission described Benefit 2(b) in the NOPR as reduced planning reserve margin, or "the reduction in capital costs of generation needed to meet resource adequacy requirements (*i.e.*, planning reserve margins) while holding loss of load probability constant."¹⁶⁶⁹ The Commission stated that investments in transmission capacity can reduce the

system-wide planning reserve margin requirement or the reserve margin requirement within individual resource adequacy zones of a transmission planning region, which can reduce the need for generation capital expenditures.¹⁶⁷⁰ The Commission also stated that it is important to note that, due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with loss of load probability, only one of these benefits should be calculated for a transmission investment, but not both simultaneously.¹⁶⁷¹ The Commission noted that RTOs/ISOs have calculated the transmission benefits of reduced planning reserve margins. MISO, for example, calculated a reduction in planning reserves associated with its Multi-Value Projects portfolio, which reduced the need for future generation buildout to meet reserve requirements, by using loss of load expectation reliability simulations. MISO estimated that its Multi-Value Projects portfolio was expected to reduce the required planning reserve margin by up to one percentage point, which translated into a projected savings of \$1.0 to \$5.1 billion in benefits over 10 years.¹⁶⁷²

(b) Comments

751. A number of commenters support mandating consideration of Benefit 2(a).¹⁶⁷³ Some commenters discuss the manner in which this benefit should be calculated.¹⁶⁷⁴ ACEG and DC and MD Offices of People's Counsel note the importance of geographic diversity between transmission planning regions as an important consideration in evaluating this benefit.¹⁶⁷⁵ Specifically, ACEG states that it can be estimated using the

¹⁶⁷⁰ *Id.* P 196.

¹⁶⁷¹ *Id.*

¹⁶⁷² *Id.* P 197 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop*, at 36–38 (Sept. 19 & 29, 2011)).

¹⁶⁷³ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

¹⁶⁷⁴ *E.g.*, ACEG Initial Comments at 38–39.

¹⁶⁷⁵ ACEG Initial Comments at 35–38; DC and MD Offices of People's Counsel Initial Comments at 21–24.

¹⁶⁶⁰ NOPR, 179 FERC ¶ 61,028 at P 193 (citing SPP, *SPP Benefit Metrics Manual*, SPP Engineering, at 15 (Nov. 6, 2020)).

¹⁶⁶¹ *Id.* (citing The Brattle Group, *Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades*, at 114 (Sept. 15, 2015)).

¹⁶⁶² West Virginia Commission Supplemental Comments at 4; Xcel Initial Comments at 13.

¹⁶⁶³ AEE Reply Comments at 26 (citing NARUC Initial Comments at 22); NARUC Initial Comments at 22.

¹⁶⁶⁴ Order No. 1000, 136 FERC ¶ 61,051 at PP 262, 329.

¹⁶⁶⁵ *Id.* P 384.

¹⁶⁶⁶ NOPR, 179 FERC ¶ 61,028 at P 194.

¹⁶⁶⁷ *Id.*

¹⁶⁶⁸ *Id.* P 195 & n.331 (citing SPP, *Benefits for the 2013 Regional Cost Allocation Review*, at 25 (Sept. 13, 2012)).

¹⁶⁶⁹ *Id.* P 194.

value of lost load and generation capital cost savings due to lower needed planning reserve margins.¹⁶⁷⁶

752. However, some commenters oppose or express concerns regarding mandating consideration of Benefit 2(a).¹⁶⁷⁷ NARUC states that transmission planners are likely already considering loss of load events in their evaluations of system expansions and that whether such benefit, in isolation, is sufficient to recommend construction of a particular transmission project is a question best left to them and their states.¹⁶⁷⁸ West Virginia Commission argues that calculation of benefits from reduced loss of load probability requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.¹⁶⁷⁹ R Street states that Benefit 2(a) should be refined to the avoided value of lost load so that it is compatible with an economic assessment, while Illinois Commission asserts that the Commission should consider a more expansive definition of reduced loss of load probability composed of more than one metric, such as value of lost load, expected unserved energy, or a hybrid measure, that can serve as a supplement to loss of load expectation.¹⁶⁸⁰

753. With respect to Benefit 2(b), a number of commenters support mandating consideration of this benefit.¹⁶⁸¹ AEP recommends including Benefit 2(b) as a part of a combination of benefits.¹⁶⁸² Pine Gate states that this proposed benefit is critical to address resource adequacy concerns, particularly where a transmission planning region relies heavily on a single generation type.¹⁶⁸³

754. With respect to comments in opposition to Benefit 2(b), similar to its comments on Benefit 2(a) above, West

Virginia Commission argues that calculation of benefits from reduced planning reserve margin requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.¹⁶⁸⁴

(c) Commission Determination

755. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 2, in Long-Term Regional Transmission Planning. This benefit can be characterized and measured as Benefit 2(a), Reduced Loss of Load Probability, or as Benefit 2(b), Reduced Planning Reserve Margin, and we clarify that these are different methods for measuring the same underlying benefit. We find that requiring the measurement and use of this benefit is necessary because it reflects an important category of reliability benefits of Long-Term Regional Transmission Facilities. Because there is an overlap between reduced loss of load probability benefits and reduced planning reserve margin benefits, for purposes of Long-Term Regional Transmission Planning, transmission providers must either measure reduced loss of load events by holding the planning reserve margin constant *or* measure the reduction in planning reserve margins by holding loss of load events constant but may not measure both simultaneously for purposes of using and measuring Benefit 2(a) or 2(b).

756. We adopt the NOPR's proposed description of Benefit 2(a) that describes Benefit 2(a), Reduced Loss of Load Probability, as the reduced frequency of loss of load events by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages (if the planning reserve margin is not changed despite lower loss of load events), as well as improved physical reliability benefits by reducing the likelihood of load shed events. Benefit 2(a) measures reduced loss of load probability for resource adequacy planning, which typically includes the consideration of normal system conditions. One method of measuring a reduction in loss of load probability benefit is to quantify the incremental increase in system reliability by determining the reduction in expected unserved energy between the base case and the change case, determining the value of lost load, and multiplying these

two values to obtain the monetary benefit of enhanced reliability associated with a Long-Term Regional Transmission Facility or a portfolio of Long-Term Regional Transmission Facilities.¹⁶⁸⁵

757. Numerous commenters support mandating Benefit 2(a).¹⁶⁸⁶ We recognize commenter suggestions regarding the method for calculating this benefit, with some recommending consideration of geographic diversity between transmission planning regions¹⁶⁸⁷ and others recommending that the benefit be expressed in terms of the value of lost load.¹⁶⁸⁸ We agree that geographic diversity is an important consideration in evaluating the reduced loss of load probability method of calculating this benefit and find that the flexibility in measuring benefits that we provide to transmission providers under this final order allows for this consideration. As to the suggestion by Illinois Commission and R Street that Benefit 2(a) should be expressed in terms of the value of lost load so that it can be expressed in terms of cost, we believe that either Benefit 2(a) or Benefit 2(b) are reasonable methods to calculate Benefit 2 and we reiterate that transmission providers can choose either method to calculate this benefit. We encourage transmission providers to consider whether Benefit 2(a) or Benefit 2(b) is the most effective way to accurately reflect the benefits of a proposed Long-Term Regional Transmission Facility in their individual regions. As to NARUC's contention that the benefit of reducing the probability of loss of load events, in isolation, may be insufficient to support the development of a particular

¹⁶⁸⁵ NOPR, 179 FERC ¶ 61,028 at P 195 & n.331 (citing SPP, *Benefits for the 2013 Regional Cost Allocation Review*, at 25 (Sept. 13, 2012)).

¹⁶⁸⁶ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

¹⁶⁸⁷ ACEG Initial Comments at 35–38; DC and MD Offices of People's Counsel Initial Comments at 21–24.

¹⁶⁸⁸ Illinois Commission Initial Comments at 14 (suggesting alternatively that Benefit 2(a) be expressed in terms of expected unserved energy, or a hybrid measurement composed of more than one metric); R Street Initial Comments at 9 (stating that using value of lost load is compatible with an economic assessment).

¹⁶⁷⁶ ACEG Initial Comments at 38.

¹⁶⁷⁷ NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

¹⁶⁷⁸ NARUC Initial Comments at 23.

¹⁶⁷⁹ West Virginia Commission Supplemental Comments at 4.

¹⁶⁸⁰ Illinois Commission Initial Comments at 14; R Street Initial Comments at 9.

¹⁶⁸¹ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

¹⁶⁸² AEP Initial Comments at 25.

¹⁶⁸³ Pine Gate Initial Comments at 37.

¹⁶⁸⁴ West Virginia Commission Supplemental Comments at 4.

transmission project, while we are requiring transmission providers to use Benefit 2(a) or Benefit 2(b) to evaluate Long-Term Regional Transmission Facilities, we are not requiring transmission providers to base their evaluation on this single benefit—or any single benefit, for that matter—but rather on at least the range of benefits included in the required set of benefits that we adopt herein. Moreover, we are not requiring that transmission providers select any Long-Term Regional Transmission Facility.

758. As noted above, the NOPR proposed the following description of Benefit 2(b), “the reduction in capital costs of generation needed to meet resource adequacy requirements (*i.e.*, planning reserve margins) while holding loss of load probability constant.”¹⁶⁸⁹ We adopt the NOPR description in this final order. We find that a lower planning reserve margin is another way to demonstrate a resource adequacy benefit. As we indicate above, due to the relationship between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with reduced loss of load probability, only one of these methods for calculating the benefit for a transmission investment can be used, but not both simultaneously. We find that Benefit 2(b) is one of two ways to calculate reduced costs related to resource adequacy because Long-Term Regional Transmission Facilities can reduce the system-wide planning reserve margin requirements within individual resource adequacy zones of a transmission planning region and provide benefits by reducing the need for generation capital expenditures.

759. Many commenters support mandating consideration of Benefit 2(b). For example, DC and MD Offices of People’s Counsel note that the benefit of a reduced reserve planning margin has been used in multiple cases.¹⁶⁹⁰ We also find that it is feasible for transmission providers to calculate the benefit of reduced planning reserve margins. We

reiterate here the example of MISO, which calculated a reduction in planning reserves associated with its Multi-Value Projects portfolio, reducing the need for future generation investments to meet reserve requirements by using loss of load expectation reliability simulations. MISO estimated that its Multi-Value Projects portfolio was expected to reduce the required planning reserve margin by up to one percentage point, which translated into a projected savings of \$1.0 to \$5.1 billion in benefits over 10 years.¹⁶⁹¹ We also note that the Commission has accepted benefits for use in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 2(a), Reduced Loss of Load Probability,¹⁶⁹² in non-RTO/ISO transmission planning regions.¹⁶⁹³

760. Finally, we disagree with West Virginia Commission’s claim that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.¹⁶⁹⁴ As noted above, there are multiple examples in the record of transmission providers that currently calculate these benefits. Because we find that transmission providers will be able to calculate either Benefit 2(a) or 2(b) and recognize the importance of accounting for Benefit 2 in Long-Term Regional Transmission Planning, we require transmission providers to measure and use Benefit 2.

iii. Benefit 3: Production Cost Savings

(a) NOPR Description

761. The Commission described Benefit 3 in the NOPR as savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as lower-cost suppliers set market clearing prices.¹⁶⁹⁵ The Commission stated that most regional transmission planning processes currently estimate production

cost savings. Generally, within RTOs/ISOs, security-constrained production cost models simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints. The traditional method for estimating the changes in adjusted production costs associated with proposed transmission facilities (or portfolio of facilities) is to compare the adjusted production costs with and without those facilities. Analysts typically call the market simulations without the proposed transmission facilities the “Base Case” and the simulations with those facilities the “Change Case.”¹⁶⁹⁶

762. The Commission further explained that approaches used to calculate production cost savings vary. MISO uses production cost savings (adjusted for import costs and export revenues) to allocate the costs of its Market Efficiency Projects to cost allocation zones based on each zone’s share of the total adjusted production cost savings.¹⁶⁹⁷ The Commission also explained, in contrast, that NYISO and PJM use reductions to load energy payments (adjusted to reflect the reduced value of transmission congestion contracts) to allocate the costs of economic transmission facilities.¹⁶⁹⁸

763. The Commission stated that non-RTO/ISO regions, without centrally organized energy markets, rely on other tools to perform analyses of production cost savings. For example, WestConnect’s regional cost allocation method for regional transmission facilities driven by economic considerations identifies the benefits and beneficiaries of a proposed regional transmission facility or facilities by modeling the potential of the transmission facilities to support more economic bilateral transactions between generators and loads in the region. Specifically, WestConnect considers the transactions between loads and lower-

¹⁶⁸⁹ NOPR, 179 FERC ¶ 61,028 at P 194.

¹⁶⁹⁰ DC and MD Offices of People’s Counsel at 22–23 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop*, at 36–38 (Sept. 19 & 29, 2011); SPP, *Benefits for the 2013 Regional Cost Allocation Review* (Sept. 13, 2012); *Investigation on Comm’n’s Own Motion to Review 18 Percent Planning Reserve Margin Requirement*, Docket No. 5–EI–141 (PSC REF# 102692), at 5 (Pub. Serv. Comm’n Wis. Oct. 9, 2008); SPP, *The Value of Transmission*, at 16 (Jan. 26, 2016); Midcontinent Independent System Operator, Inc., *MISO Value Proposition 2020: Forward View*, at 20–21 (June 2022); PJM Interconnection, L.L.C., *PJM Value Proposition*, at 2 (2019); Australian Energy Market Operator, *2022 Integrated System Plan*, at 64 (June 2022)).

¹⁶⁹¹ NOPR, 179 FERC ¶ 61,028 at P 197 (citing Midcontinent Independent System Operator, Inc., *Proposed Multi Value Project Portfolio: Business Case Workshop*, at 36–38 (Sept. 19 & 29, 2011)).

¹⁶⁹² *PacifiCorp*, 147 FERC ¶ 61,057 at PP 133–134, 141–143; *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206 at P 314.

¹⁶⁹³ *PacifiCorp*, 147 FERC ¶ 61,057 at PP 132, 134, 141–143.

¹⁶⁹⁴ West Virginia Commission Supplemental Comments at 4.

¹⁶⁹⁵ NOPR, 179 FERC ¶ 61,028 at P 198 & n.333 (proposing to define this as adjusted production cost savings when the calculation is adjusted to account for purchases and sales outside the region).

¹⁶⁹⁶ NOPR, 179 FERC ¶ 61,028 at P 199.

¹⁶⁹⁷ NOPR, 179 FERC ¶ 61,028 at P 200 (citing MISO, FERC Electric Tariff, attach. FF, Benefit Metrics section (I)(A)(1) (33.0.0)).

¹⁶⁹⁸ NOPR, 179 FERC ¶ 61,028 at P 200 & n.335 (citing *PJM Interconnection L.L.C.*, 142 FERC ¶ 61,214 at P 416; *N.Y. Indep. Sys. Operator Corp.*, 143 FERC ¶ 61,059, at PP 268, 269, n.516 (2013); NYISO, NYISO Tariffs, OATT, attach. Y, section 31.5 (Cost Allocation and Cost Recovery) (30.0.0), section 31.5.4.3.2.) (“For high voltage economic transmission facilities, PJM allocates 50% of the costs in accordance with its economic analysis and allocates the other 50% of the costs on a load-ratio share basis.”).

cost generation that a proposed regional transmission facility could support and, accounting for the costs associated with transmission service, identifies the transactions that are likely to occur. WestConnect then estimates any resulting cost savings (in the form of reductions in production costs and reserve sharing requirements) and allocates the costs of the regional transmission facilities on that basis.¹⁶⁹⁹

(b) Comments

764. A number of commenters support mandating consideration of this benefit.¹⁷⁰⁰ AEP recommends including Benefit 3 as a part of a combination of benefits.¹⁷⁰¹ According to TAPS, all of the RTOs/ISOs already consider production cost savings; TAPS argues that the Commission should require transmission providers in non-RTO/ISO transmission planning regions to consider them as well.¹⁷⁰² Indicated PJM TOs state that this benefit is one of the main benefits that will drive the selection of transmission facilities in PJM.¹⁷⁰³

765. Some commenters opine on how to calculate this benefit.¹⁷⁰⁴ ACEG states that production cost savings should include fuel and variable operating cost savings, adjustments for imports from neighboring transmission planning regions, reduced costs of cycling power plants, reduced amounts and costs of operating reserves and other ancillary services, and mitigation of reliability-must-run conditions.¹⁷⁰⁵ Likewise, DC and MD Offices of People's Counsel state that production cost savings

should include ancillary service cost savings.¹⁷⁰⁶ MISO notes that, in addition to evaluating production cost savings under normal patterns of renewable dispatch and load, transmission providers can analyze production cost savings that accrue during transmission outages using historical sampling or statistical modeling of transmission outage patterns.¹⁷⁰⁷ MISO TOs state that its process to evaluate Multi-Value Projects considers production cost savings that can be realized through reduced transmission congestion and transmission energy losses, capacity loss savings, capacity savings, long-term cost savings, and "any other financially quantifiable benefit."¹⁷⁰⁸

766. Some commenters oppose or express concerns regarding mandating consideration of production cost savings.¹⁷⁰⁹ For example, Southern states that considering production cost savings could result in the double-counting of benefits in its footprint by, for example, making generation pricing/cost decisions that have already been made or will ultimately be made in integrated resource planning or request for proposal processes.¹⁷¹⁰ Relatedly, North Carolina Commission and Staff state that requiring consideration of production cost savings would conflict with state-jurisdictional resource decisions.¹⁷¹¹ Mississippi Commission contends that this benefit may not always be applicable, such as where financial transmission rights fully hedge the cost of congestion.¹⁷¹² PJM Market Monitor states that in PJM, comparing production cost savings across different gas prices and different generation resource capacity may not provide meaningful guidance as to the benefits of a transmission facility beyond that currently provided by satisfying reliability criteria because of potentially inaccurate forecasts for key values.¹⁷¹³ Pacific Northwest Utilities assert that

this benefit is not easily quantifiable.¹⁷¹⁴

(c) Commission Determination

767. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 3, Production Cost Savings, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 3 as savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production, as well as a reduction in market prices as lower-cost suppliers set market clearing prices. We find that requiring the use of Benefit 3 is necessary because Long-Term Regional Transmission Facilities could result in savings in fuel and other variable operating costs of power generation that are realized when transmission facilities allow for displacement of higher-cost supplies through the increased dispatch of suppliers that have lower incremental costs of production. We further find that, absent a requirement for transmission providers to measure and use Benefit 3 in Long-Term Regional Transmission Planning, transmission providers may not identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

768. We do not require a standardized method for measuring production cost savings, and, consistent with this approach, we decline commenter requests to specify the exact types of cost savings for which transmission providers must account when measuring this benefit.¹⁷¹⁵ As the Commission stated in the NOPR,¹⁷¹⁶ different transmission planning regions have different approaches toward the calculation of this benefit, and this final order provides flexibility for transmission providers in developing the method that they use to measure production cost savings, consistent with the requirement to measure and use the required set of benefits in Long-Term Regional Transmission Planning described above.

¹⁶⁹⁹ NOPR, 179 FERC ¶ 61,028 at P 201 (citing *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206 at P 314).

¹⁷⁰⁰ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Certain TDUs Reply Comments at 1–2; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Joint Consumer Advocates Initial Comments at 11; New Jersey Commission Initial Comments at 13–14 (including reduced production costs during transmission outages, extreme events, and higher than normal load conditions in Benefit 3); Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; PJM Initial Comments at 96; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; TAPS Initial Comments at 14; US DOE Initial Comments at 31–32.

¹⁷⁰¹ AEP Initial Comments at 25.

¹⁷⁰² TAPS Initial Comments at 14.

¹⁷⁰³ Indicated PJM TOs Initial Comments at 17.

¹⁷⁰⁴ ACEG Initial Comments at 40; DC and MD Offices of People's Counsel Initial Comments at 25; GridLab Initial Comments at 26–27; MISO Initial Comments at 49–50.

¹⁷⁰⁵ ACEG Initial Comments at 40.

¹⁷⁰⁶ DC and MD Offices of People's Counsel Initial Comments at 25.

¹⁷⁰⁷ MISO Initial Comments at 49–50.

¹⁷⁰⁸ MISO TOs Initial Comments at 21 (citing MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff, attach. FF (90.0.0), section II.C.5).

¹⁷⁰⁹ Mississippi Commission Initial Comments at 35–36; North Carolina Commission and Staff Initial Comments at 7; Pacific Northwest Utilities Initial Comments at 9; PJM Market Monitor Initial Comments at 5; Southern Initial Comments at 26.

¹⁷¹⁰ Southern Initial Comments at 26 (citing Southern Initial Comments Ex. 1, ¶¶ 8, 15).

¹⁷¹¹ North Carolina Commission and Staff Initial Comments at 7.

¹⁷¹² Mississippi Commission Initial Comments at 36.

¹⁷¹³ PJM Market Monitor Initial Comments at 5.

¹⁷¹⁴ Pacific Northwest Utilities Initial Comments at 9.

¹⁷¹⁵ See ACEG Initial Comments at 40; DC and MD Offices of People's Counsel Initial Comments at 25; GridLab Initial Comments at 26–27; MISO Initial Comments at 49–50.

¹⁷¹⁶ NOPR, 179 FERC ¶ 61,028 at PP 200–201.

769. We note that Benefit 3 is distinct from other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning. Although Benefit 3 and Benefit 6, as described in this final order, both measure production cost savings (including savings that occur during generation outage contingencies), the system conditions used in calculating each benefit are distinct. For example, Benefit 6 can include higher electricity demand, forecast errors, volatile production costs, and a more expansive set of generation outages such as unplanned generation outages due to extreme weather. And as we discuss below in the context of Benefit 5, because Benefit 3, Production Cost Savings, as described in this order, does not capture production cost savings during transmission outages, we require transmission providers to measure and use Benefit 5 to ensure that they are accounting for reduced production costs during transmission outages as well.

770. We also do not believe that requiring transmission providers to measure and use Benefit 3 in Long-Term Regional Transmission Planning will, as Southern suggests, result in double-counting of benefits because such benefits are also considered in state resource planning. While we acknowledge that integrated resource planning processes, where they exist, may consider similar benefits compared to those required by this final order, the consideration of benefits in a state-jurisdictional process does not result in the double-counting of benefits within any Commission-jurisdictional transmission planning process. Because practices affecting rates, terms, and conditions for interstate transmission service are the exclusive jurisdiction of the Commission, we must ensure that Commission-jurisdictional regional transmission planning processes result in rates that are just and reasonable and not unduly or discriminatory. To this end, this final order is focused on ensuring that, when conducting Long-Term Regional Transmission Planning, transmission providers consider the broader set of benefits provided by Long-Term Regional Transmission Facilities so that they may determine whether to select such facilities as the more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs.

771. Pacific Northwest Utilities assert that production cost savings are not easily quantifiable.¹⁷¹⁷ We acknowledge

that there are some challenges associated with measuring this benefit, but we conclude that it is nonetheless necessary to require such measurement in order to ensure that transmission rates are just, reasonable, and not unduly discriminatory or preferential. We also note that there is an abundance of examples of how transmission providers can measure this benefit. Production cost savings are used extensively in many transmission planning regions, including MISO, NYISO, PJM, SPP, CAISO, ISO-NE, NorthernGrid, and WestConnect.¹⁷¹⁸ We believe that transmission providers are capable of measuring production cost savings given that this benefit has been used as a metric in transmission planning for decades.

772. In response to North Carolina Commission and Staff's contention that requiring consideration of production cost savings conflicts with state-jurisdictional resource decisions,¹⁷¹⁹ we find that North Carolina Commission and Staff have failed to explain why there may be a conflict. As noted in the Need for Reform, there are deficiencies in the Commission's existing transmission planning and cost allocation requirements, including that they fail to require transmission providers to adequately consider the broader set of benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. We are concerned that failing to adequately identify and consider the benefits, including production cost benefits, of such transmission facilities may lead to relatively inefficient and less cost-effective transmission development. Additionally, as described above in the Categories of Factors section, transmission providers must incorporate, and not discount, state-

¹⁷¹⁸ See NOPR, 179 FERC ¶ 61,028 at PP 200–201; Brattle-Grid Strategies Oct. 2021 Report at 31; ISO New England, Inc., *Transmission Planning: Maintaining Power System Reliability Amid Change*, <https://www.iso-ne.com/system-planning/transmission-planning> (last visited Mar. 25, 2024); NorthernGrid, *Study Scope for the 2022–2023 NorthernGrid Planning Cycle*, 2 (Sept. 21, 2022), https://www.northerngrid.net/private-media/documents/NG_Study_Scope_2022-2023_Approved.pdf; The Brattle Group, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, 31 (July 2013), <https://www.brattle.com/wp-content/uploads/2021/06/The-Benefits-of-Electric-Transmission-Identifying-and-Analyzing-the-Value-of-Investments.pdf> (noting that in the Western Electricity Coordinating Council (WECC), whose service area includes one RTO (CAISO) and three non-RTO regions (ColumbiaGrid, Northern Tier Transmission Group (NTTG), and WestConnect) production costs simulations are used to calculate the energy costs savings of transmission projects in WECC's long-term transmission planning studies).

¹⁷¹⁹ North Carolina Commission and Staff Initial Comments at 7.

jurisdictional resource decisions, such as integrated resource plans, into all Long-Term Scenarios to identify Long-Term Transmission Needs. Therefore, we believe that requiring transmission providers to measure production cost savings will not conflict with state-jurisdictional resource decisions, because the effects of such resource decisions on Long-Term Transmission Needs must be fully accounted for in all Long-Term Scenarios, which are used to help identify more efficient or cost-effective regional transmission solutions within the Commission-jurisdictional regional transmission planning process. Moreover, as discussed in the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section of this final order, nothing in this final order conflicts with or infringes on the states' reserved authority under FPA section 201.

773. We disagree with Mississippi Commission's assertion that production cost savings may not always be applicable, such as where financial transmission rights fully hedge the cost of congestion.¹⁷²⁰ Financial transmission rights are required in RTO/ISO markets and allow the market participant that owns the right to mitigate the congestion charge along an existing transmission path for the capacity of that path.¹⁷²¹ A new transmission facility could reduce congestion and allow that market participant to purchase more electricity, exceeding the capacity of the transmission path for the financial transmission right, at a lower price. This reduced congestion allows for load to access lower cost resources, and results in more efficient dispatch of resources and, thus, provides avoided production cost benefits that are distinct from the avoided congestion charges associated with financial transmission rights.

774. We recognize the PJM Market Monitor's concern regarding the potential for inaccurate forecasts of key inputs to the calculation of production cost savings.¹⁷²² However, we conclude that this potential concern does not outweigh the value of measuring and using this benefit, as demonstrated by long-standing use of this benefit within PJM and other transmission planning regions, including all RTOs/ISOs and some non-RTO/ISO regions. Moreover,

¹⁷²⁰ Mississippi Commission Initial Comments at 36.

¹⁷²¹ *Long-Term Firm Transmission Rights in Organized Elec. Mkts.*, Order No. 681, 116 FERC ¶ 61,077, at PP 5, 19–21, *reh'g denied*, Order No. 681–A, 117 FERC ¶ 61,201 (2006), *order on reh'g & clarification*, Order No. 681–B, 126 FERC ¶ 61,254 (2009).

¹⁷²² PJM Market Monitor Initial Comments at 5.

¹⁷¹⁷ Pacific Northwest Utilities Initial Comments at 9.

as noted in the Long-Term Scenarios section of this final order, the use of Long-Term Scenarios in Long-Term Regional Transmission Planning mitigates such uncertainty in transmission planning outcomes. Specifically, comparing the production cost savings, as well as the other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning, provided by Long-Term Transmission Facilities across three distinct Long-Term Scenarios should help to address the uncertainty noted by the PJM Market Monitor.

iv. Benefit 4: Reduced Transmission Energy Losses

(a) NOPR Description

775. The Commission described this benefit in the NOPR as reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmittal of power from generation to loads.¹⁷²³

776. The Commission explained that production cost savings metrics used today typically exclude reduced transmission energy losses and three other production cost savings-related benefits proposed in the NOPR. The Commission also stated that including those additional proposed benefits can produce a more robust set of congestion and production cost benefits that can be quantified and integrated into the method for calculating production cost savings and, therefore, help to ensure that more efficient or cost-effective transmission facilities are selected through Long-Term Regional Transmission Planning.¹⁷²⁴

777. The Commission noted that to measure reduced transmission energy losses, transmission providers could: (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for a range of hours; or (3) estimate how the cost of supplying losses will likely change with marginal loss charges. For example, ATC measured reduced transmission energy losses based on changes in marginal loss charges and loss refund estimates using the marginal loss component from the PROMOD¹⁷²⁵ electric market simulation software simulations for the Paddock-Rockdale 345 kV Access Project,¹⁷²⁶ which

produced cost reduction benefits using adjusted production cost analysis. Also, SPP's analysis for its Regional Cost Allocation Review process estimated energy loss reductions through post-processing the marginal loss component of the locational marginal prices in PROMOD simulation results.¹⁷²⁷

(b) Comments

778. A number of commenters support mandating consideration of Benefit 4.¹⁷²⁸ While not favoring a benefits measurement requirement, Southern states that this benefit would likely prove workable under Southern's non-RTO/ISO construct because SERTP Sponsors' regional and interregional transmission planning and cost allocation processes already incorporate the benefit of reduced transmission energy losses.¹⁷²⁹

779. Several commenters comment on the manner in which Benefit 4 should be calculated.¹⁷³⁰ ACEG states that this benefit has been calculated in various studies.¹⁷³¹

780. West Virginia Commission opposes the use of Benefit 4, arguing that the calculation of benefits from reduced transmission losses requires significant evidence based on assumptions that are difficult, if not impossible, to quantify before the fact.¹⁷³²

Rockdale Project, Docket No. 137–CE–149, app. C, Ex. 1, at 34–38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007).

¹⁷²⁷ SPP, *SPP Regional Cost Allocation Review Report for RCAR II*, at 56, 64 (July 11, 2016), <https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf>.

¹⁷²⁸ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 13–14; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

¹⁷²⁹ Southern Initial Comments at 25.

¹⁷³⁰ ACEG Initial Comments at 41; NARUC Initial Comments at 23 (noting that advanced technologies also provide this benefit and should be preferred over greenfield construction); Utah Division of Public Utilities Initial Comments at 8.

¹⁷³¹ ACEG Initial Comments at 41 (citing ATC, Planning Analysis of the Paddock-Rockdale Project, app. C Ex. 1, at 34–38 (Wisc. Pub. Serv. Docket No. 137–CE–149); SPP, *Regional Cost Allocation Review Report for RCAR II*, at 5 (July 11, 2016), <https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf>).

¹⁷³² West Virginia Commission Supplemental Comments at 4.

(c) Commission Determination

781. We adopt the NOPR proposal, with modification, to require transmission providers to measure and use Benefit 4, Reduced Transmission Energy Losses, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 4, as modified, as the reduced total energy necessary to meet demand stemming from reduced energy losses incurred in transmittal of power from generation to loads. We find that requiring the measurement and use of Benefit 4 in Long-Term Regional Transmission Planning is necessary because reduced energy losses are widely understood to be a benefit of transmission facilities.¹⁷³³ As such, we find that transmission providers must measure and use this benefit in Long-Term Regional Transmission Planning because it will help to ensure that they identify, evaluate, and select more efficient or cost-effective regional transmission solutions to address Long-Term Transmission Needs.

782. We recognize that there are multiple ways for transmission providers to measure reduced transmission energy losses.¹⁷³⁴ We note that this final order does not require transmission providers to adopt any single method to measure reduced transmission energy losses. As described in the NOPR, transmission providers could: (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for a range of hours; or (3) estimate how the cost of supplying losses will likely change with marginal loss charges.¹⁷³⁵ Transmission providers could also follow the example of ATC, which measured reduced transmission energy losses based on changes in marginal loss charges and loss refund estimates provided by the PROMOD electric market simulation software.¹⁷³⁶

¹⁷³³ See Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 19–20; ENGIE Reply Comments at 3; Hannon Armstrong Initial Comments at 3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 11–14; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 38–41; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

¹⁷³⁴ See, e.g., ACEG Initial Comments at 41 (citing studies in which Benefit 4 has been calculated).

¹⁷³⁵ NOPR, 179 FERC ¶ 61,028 at P 204.

¹⁷³⁶ ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137–CE–149, app. C

¹⁷²³ NOPR, 179 FERC ¶ 61,028 at P 202.

¹⁷²⁴ *Id.* P 203.

¹⁷²⁵ PROMOD is a generator and portfolio modeling system. Hitachi Energy: PROMOD, <https://www.hitachienergy.com/us/en/products-and-solutions/energy-portfolio-management/enterprise/promod> (last visited Apr. 2024).

¹⁷²⁶ NOPR, 179 FERC ¶ 61,028 at P 204 & n.338 (citing ATC, Planning Analysis of the Paddock-

Similarly, SPP estimates energy loss reductions through its Regional Cost Allocation Review process by post-processing the marginal loss component of the locational marginal prices in PROMOD simulation results.¹⁷³⁷

783. Because we find that transmission providers have multiple ways of calculating the benefit of reduced transmission energy losses, as well as record evidence demonstrating that the calculation of Benefit 4 is either already considered or is feasible in multiple transmission planning regions, we disagree with West Virginia Commission's claim that calculation of this benefit requires evidence based on assumptions that are difficult, if not impossible, to quantify in advance.¹⁷³⁸ We also note that the Commission has accepted benefits for use in evaluating regional transmission facilities in Order No. 1000 regional transmission planning processes akin to Benefit 4, Reduced Transmission Energy Losses, in non-RTO/ISO transmission planning regions.¹⁷³⁹

v. Benefit 5: Reduced Congestion Due to Transmission Outages

(a) NOPR Description

784. The Commission described Benefit 5 in the NOPR as reduced production costs resulting from avoided congestion during transmission outages. Such benefits include reduced production costs during transmission outages that significantly increase transmission congestion. Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect transmission outages, planned or unplanned.¹⁷⁴⁰ The Commission noted that transmission providers could measure this benefit, for example, by either building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by inducing system constraints more frequently. One application of this approach is SPP's Regional Cost Allocation Review process, which, inter-

alia, measured the benefits of reducing congestion resulting from transmission outages. In this process, SPP modeled outage events and new constraints based on these outages in PROMOD for a 2025 case year, and then conducted PROMOD simulations to calculate adjusted production cost savings for a base case and the change case including the transmission line.¹⁷⁴¹

(b) Comments

785. A number of commenters support mandating consideration of Benefit 5.¹⁷⁴² While Southern does not support a requirement to use this or other benefits, it states that this benefit—which Southern understands as “operational flexibility”—could be explored for potential adoption in its footprint.¹⁷⁴³

786. A few commenters opine on how to calculate the benefit of reduced congestion due to transmission outages.¹⁷⁴⁴ ACEG states that most transmission planning models ignore unplanned transmission outages that are likely to occur during extreme weather events, which ACEG claims will underestimate the value of Benefit 5.¹⁷⁴⁵ Similarly, DC and MD Offices of People's Counsel argue that, because unplanned transmission outages cause a significant portion of congestion costs, calculation of this benefit should account for such outages.¹⁷⁴⁶

¹⁷⁴¹ *Id.* P 205 & n.341 (citing SPP, Inc., *Regional Cost Allocation Review Report for RCAR II*, at 51–52 (July 11, 2016), <https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf>. To estimate incremental savings associated with mitigation of transmission outage costs, SPP analyzed outage cases in PROMOD for the 2025 study year. SPP developed cases based on 12 months of historical SPP transmission data. SPP said that because of the high volume of historical transmission outage data (approximately 7,000 outage events) and based on the expectation that many outages would not lead to significant increases in congestion, SPP only modeled a subset of outage events. The events selected were those expected to create significant congestion and met at least one of three conditions. *Id.* at 51.)

¹⁷⁴² Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

¹⁷⁴³ Southern Initial Comments at 25.

¹⁷⁴⁴ ACEG Initial Comments at 41–42; DC and MD Offices of People's Counsel Initial Comments at 25–26.

¹⁷⁴⁵ ACEG Initial Comments at 41.

¹⁷⁴⁶ DC and MD Offices of People's Counsel Initial Comments at 25–26.

787. Some commenters oppose mandating consideration of Benefit 5.¹⁷⁴⁷ AEP argues that reduced congestion due to transmission outages is of lesser importance and does not need to be in the required minimum set of benefits.¹⁷⁴⁸ NARUC states that benefits associated with new construction to alleviate congestion is already a planning consideration.¹⁷⁴⁹ Pacific Northwest Utilities and West Virginia Commission assert that this benefit is not easily quantifiable.¹⁷⁵⁰ Idaho Power states that non-RTO/ISO transmission planning regions may not be able to calculate reduced congestion.¹⁷⁵¹

(c) Commission Determination

788. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Benefit 5, Reduced Congestion Due to Transmission Outages, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Benefit 5 as reduced production costs resulting from avoided congestion during transmission outages. Such benefits include reduced production costs during transmission outages that significantly increase transmission congestion. We find that requiring the measurement and use of Benefit 5, as described, is necessary because reduced congestion due to transmission outages is widely understood to be a benefit of transmission facilities.¹⁷⁵² As such, we find that transmission providers must measure and use this benefit in Long-Term Regional Transmission Planning because it will help to ensure that they identify, evaluate, and select more efficient or cost-effective regional

¹⁷⁴⁷ AEP Initial Comments at 27–28; NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

¹⁷⁴⁸ AEP Initial Comments at 27.

¹⁷⁴⁹ NARUC Initial Comments at 23.

¹⁷⁵⁰ Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

¹⁷⁵¹ Idaho Power Initial Comments at 8.

¹⁷⁵² See Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

Ex. 1, at 34–38 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007).

¹⁷³⁷ SPP, *Regional Cost Allocation Review Report for RCAR II*, at 56, 64 (July 11, 2016), <https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf>.

¹⁷³⁸ West Virginia Commission Supplemental Comments at 4.

¹⁷³⁹ *PacifiCorp*, 147 FERC ¶ 61,057 at PP 132, 134, 141–143.

¹⁷⁴⁰ NOPR, 179 FERC ¶ 61,028 at P 205 & n.340 (citing Brattle-Grid Strategies Oct. 2021 Report at 79).

transmission solutions to address Long-Term Transmission Needs.

789. We also find that consideration of Benefit 5 is necessary because most current production cost simulations only consider generation outages—both planned generation outages and random distributions of unplanned generation outages; by contrast, production cost simulations do not typically address transmission outages, either planned or unplanned. Given that transmission facilities can provide benefits by reducing production costs during both generation outages and transmission outages, we find that it is necessary for transmission providers to measure and use production cost savings during both generation outages and transmission outages in Long-Term Regional Transmission Planning. Because Benefit 3, Production Cost Savings, as described in this order does not capture production cost savings during transmission outages, we require transmission providers to measure and use Benefit 5 to ensure that they are accounting for reduced production costs during transmission outages as well. We note that Benefit 6 is distinct from other benefits that we require transmission providers to measure and use in Long-Term Regional Transmission Planning. Although Benefit 5 and Benefit 6 both measure the benefit of reduced congestion due to transmission outages, the system conditions used to measure Benefit 6 include a more expansive set of transmission outages such as unplanned outages due to extreme weather.

790. For the reasons stated above, we disagree with AEP's arguments that reduced congestion due to transmission outages is less important than other benefits and thus should not be required.¹⁷⁵³ And while some commenters object to consideration of reduced congestion due to transmission outages as a benefit on the grounds that this benefit is not easily quantifiable,¹⁷⁵⁴ we believe this benefit is merely another variant in production cost savings modeling that we already require for other benefits, such as Benefits 3 and 4.

vi. Benefit 6: Mitigation of Extreme Weather Events and Unexpected System Conditions

(a) NOPR Description

791. The Commission described the benefit of mitigation of extreme events and system contingencies in the NOPR

as reductions in production costs resulting from reduced high-cost generation and emergency procurements necessary to support the transmission system during extreme events (such as unusual weather conditions, fuel shortages, or multiple or sustained generation and transmission outages) and system contingencies.¹⁷⁵⁵ These benefits include reduced production costs during extreme events facilitated by a more robust transmission system that reduces high-cost generation and emergency procurements necessary to support the system.¹⁷⁵⁶ The Commission noted that transmission providers can measure benefits from the mitigation of extreme events and system contingencies by calculating the probability-weighted production cost savings through production cost simulation for a set of extreme historical market conditions. The Commission provided as one example CAISO's analysis of Devers-Palo Verde Line No. 2, where CAISO modeled several contingencies to determine the value of the line during high-impact, low-probability events and, as another example, ATC's production cost simulation analysis of insurance benefits for the ATC Paddock-Rockdale transmission line. ATC found that probability-weighted savings from reducing production and power purchase costs during a number of simulated extreme events offset 20% of total project costs.¹⁷⁵⁷ The Commission also noted that a study found development of an additional 1,000 MW of transmission capacity into Texas would have fully paid for itself over four days during Winter Storm Uri and the same into MISO would have saved \$100 million during the same time period.¹⁷⁵⁸

792. Separately, the Commission described the benefit of mitigation of weather and load uncertainty in the NOPR as reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns.¹⁷⁵⁹ The Commission stated that this is beyond

the effects of extreme weather described above and may account for, for example, regional and sub-regional load variances that will occur due to changing weather patterns.¹⁷⁶⁰ The Commission provided, as one example, simulations that ERCOT performed for normal loads, higher-than-normal loads, and lower-than-normal loads for a Houston import project, which showed increased benefits with a probability-weighted average for all three simulated load conditions.¹⁷⁶¹

(b) Comments

793. A number of commenters support mandating consideration of the benefit of mitigation of extreme events and system contingencies.¹⁷⁶² For instance, Grid United states that extreme weather conditions significantly affect the electric grid and that requiring transmission providers to consider transmission projects based on their ability to mitigate extreme weather events will enhance resilience.¹⁷⁶³ ACEG and DC and Maryland Offices of People's Counsel state that consideration of the benefit of mitigation of extreme events and system contingencies is merited given "the hundreds of millions of dollars that would have been saved if transmission capacity had been greater during a number of actual severe weather episodes."¹⁷⁶⁴ Clean Energy Associations assert that transmission providers should not calculate benefits

¹⁷⁶⁰ *Id.*

¹⁷⁶¹ *Id.* P 209 & n.345 (citing ERCOT, *Economic Planning Criteria: Question 1: 1/7/2011 Joint CMWG/PLWG Meeting*, at 10 (Mar. 4, 2011)). The \$57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant Energy estimated probabilities for the same scenarios).

¹⁷⁶² Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; ACORE Supplemental Comments at 1; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Grid United Initial Comments at 3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; PJM Initial Comments at 94 (in combination with Benefit 7, noting that significant stakeholder engagement is needed to implement); RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32; US Senator Schumer Supplemental Comments at 2–3.

¹⁷⁶³ Grid United Initial Comments at 3.

¹⁷⁶⁴ ACEG Initial Comments at 43 & n.119; DC and Maryland Offices of People's Counsel Initial Comments at 26–27 & n.65 (both citing Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (Jul. 2021), https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf).

¹⁷⁵³ AEP Initial Comments at 27.

¹⁷⁵⁴ See Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

¹⁷⁵⁵ NOPR, 179 FERC ¶ 61,028 at P 206.

¹⁷⁵⁶ *Id.*

¹⁷⁵⁷ *Id.* P 207 & n.342 (*Opinion Granting Certificate of Public Convenience and Necessity, In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Devers-Palo Verde No. 2 Transmission Line Project*, Application 05–04–015 (Cal. Comm'n Jan. 27, 2007)) & n.343 (ATC, Planning Analysis of the Paddock-Rockdale Project, Docket No. 137–CE–149, app. C, Ex. 1, at 4, 50–53 (Wisc. Pub. Serv. Comm'n Apr. 5, 2007)).

¹⁷⁵⁸ *Id.* P 207 & n.344 (M. Goggin, Grid Strategies, LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2020)).

¹⁷⁵⁹ *Id.* P 208.

solely based on average system conditions, as transmission investments can provide significant benefits during abnormal or extreme conditions or events.¹⁷⁶⁵

794. Some commenters comment on the manner in which the benefit of mitigation of extreme events and system contingencies should be calculated.¹⁷⁶⁶ ACEG states that the benefit of mitigation of extreme events and system contingencies can be calculated by retrospective analysis or probabilistically. Additionally, ACEG recommends that the Commission require transmission providers to include avoided scarcity pricing, storm hardening and wildfire resilience, grid strength, and increased fuel diversity and system flexibility in addition to production cost savings when calculating the benefit of mitigation of extreme events and system contingencies.¹⁷⁶⁷ Similarly, DC and MD Offices of People's Counsel assert that the benefit of mitigation of extreme events and system contingencies should include resilience benefits such as storm and wildfire hardening, fuel diversity, and system flexibility, as well as reduced prices to consumers given that many regions set scarcity prices at values higher than generator production costs.¹⁷⁶⁸

795. A number of commenters also support mandating consideration of the benefit of mitigation of weather and load uncertainty.¹⁷⁶⁹ Some commenters comment on the manner in which the benefit of mitigation of weather and load uncertainty should be calculated.¹⁷⁷⁰ GridLab posits that

mitigation of weather and load uncertainty should only be included in the context of planning and operating reserves because “the cost to system operators of mitigating uncertainty is [the same as] the cost of holding additional reserves.”¹⁷⁷¹

796. Other commenters oppose mandating consideration of the benefit of mitigation of extreme events and system contingencies, arguing that it is challenging to quantify and that its calculation entails subjective judgment.¹⁷⁷² Louisiana Commission states that the value of mitigating extreme weather events can vary significantly across transmission planning regions and states. Louisiana Commission opposes any extreme weather benefit category that would result in the assignment of costs of transmission hardening projects to Louisiana ratepayers from which they do not benefit. Louisiana Commission further states that any analysis of this benefit should be limited to sensitivities.¹⁷⁷³

797. Some commenters oppose mandating consideration of the mitigation of weather and load uncertainty.¹⁷⁷⁴ AEP states that this benefit should not be included in the minimum set of benefits because it is of lesser importance than other benefits described in the NOPR.¹⁷⁷⁵ NRECA argues that quantifying this benefit requires subjective judgment.¹⁷⁷⁶ According to Pacific Northwest Utilities, this benefit accrues to generation and load-serving entities, not to transmission providers.¹⁷⁷⁷

798. NARUC states that the benefits of mitigation of extreme events, system contingencies, weather, and load uncertainties may be more appropriate for consideration in interregional transmission planning, depending on the size of the transmission planning region. While NARUC states that mitigation of such contingencies is among the soundest reasons for Interregional Transfer Capability planning, it also notes that in regions with a large footprint (e.g., PJM, MISO) it may be possible to assess these

resilience benefits in the regional transmission planning process.¹⁷⁷⁸

799. MISO states that the treatment of mitigation of extreme events and system contingencies and mitigation of weather and load uncertainty as economic benefits differ only to the degree at which production cost savings are realized. MISO also states that “mitigation of extreme events” may be represented as a reliability benefit where a value of outage costs can be used to monetize the benefits of mitigating the risk of load shedding.¹⁷⁷⁹ PJM suggests that the Commission should consolidate the benefits of mitigation of extreme events and system contingencies and the benefits of mitigation of weather and load uncertainty into a single enhanced reliability benefit that would evaluate the ability of grid enhancements to serve load reliably under extreme events and vulnerabilities.¹⁷⁸⁰ MISO and NARUC state that their comments regarding mitigation of extreme events and system contingencies are equally applicable to mitigation of weather and load uncertainty.¹⁷⁸¹

(c) Commission Determination

800. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Final Order Benefit 6, mitigation of extreme weather events and unexpected system conditions, in Long-Term Regional Transmission Planning. The revised Final Order Benefit 6 modifies and combines two of the benefits proposed in the NOPR: (1) mitigation of extreme events and system contingencies (NOPR Benefit 6) and (2) mitigation of weather and load uncertainty (NOPR Benefit 7).¹⁷⁸² In combining these two proposed NOPR benefits, we modify the description of NOPR Benefit 6 and describe Final Order Benefit 6 as reduced production costs and reduced loss of load (or emergency procurements necessary to support the system), including due to increased Interregional Transfer Capability, during extreme weather events and unexpected system conditions, such as unusual weather conditions or fuel shortages that result in multiple concurrent and sustained generation and/or transmission outages. The description of Final Order Benefit 6 that we adopt in this final order

¹⁷⁶⁵ Clean Energy Associations Initial Comments at 21.

¹⁷⁶⁶ ACEG Initial Comments at 43; Clean Energy Associations Initial Comments at 21; DC and MD Offices of People's Counsel Initial Comments at 26–27; MISO Initial Comments at 51; NARUC Initial Comments at 23; Pacific Northwest Utilities Initial Comments at 9.

¹⁷⁶⁷ ACEG Initial Comments at 43–44.

¹⁷⁶⁸ DC and MD Offices of People's Counsel Initial Comments at 26–27.

¹⁷⁶⁹ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2–3; Grid United Initial Comments at 3; Hannon Armstrong Initial Comments at 2–3; Interwest Initial Comments at 12–14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; PJM Initial Comments at 94 (in combination with Benefit 6, noting that significant stakeholder engagement would be necessary to implement); RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; US DOE Initial Comments at 31–32.

¹⁷⁷⁰ ACEG Initial Comments at 44; GridLab Initial Comments at 26; NARUC Initial Comments at 23.

¹⁷⁷¹ GridLab Initial Comments at 26.

¹⁷⁷² NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

¹⁷⁷³ Louisiana Commission Initial Comments at 18–19.

¹⁷⁷⁴ AEP Initial Comments at 27; NARUC Initial Comments at 23; NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9.

¹⁷⁷⁵ AEP Initial Comments at 27.

¹⁷⁷⁶ NRECA Initial Comments at 45.

¹⁷⁷⁷ Pacific Northwest Utilities Initial Comments at 9.

¹⁷⁷⁸ NARUC Initial Comments at 21, 23.

¹⁷⁷⁹ MISO Initial Comments at 51.

¹⁷⁸⁰ PJM Initial Comments at 94.

¹⁷⁸¹ MISO Initial Comments at 51; NARUC Initial Comments at 23.

¹⁷⁸² NOPR, 179 FERC ¶ 61,028 at PP 206–207 (NOPR Benefit 6), 208–209 (NOPR Benefit 7).

includes three additional modifications to the NOPR proposals describing NOPR Benefit 6 and NOPR Benefit 7. First, we require transmission providers to measure, as part of Benefit 6,¹⁷⁸³ the benefits of reduced loss of load (not only reduced production costs). Second, we require transmission providers, as part of Benefit 6, to account for both extreme weather events and unexpected system conditions when transmission facilities have particularly high value. The unexpected system conditions can include, for example, system contingencies in the form of generator and/or transmission outages, extreme or volatile production costs, and generation and/or load forecast errors. Third, we require transmission providers to measure, as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability provided by a Long-Term Regional Transmission Facility during an extreme weather event or unexpected system condition that results in multiple and concurrent sustained generation and/or transmission outages.

801. We find that requiring the measurement and use of Benefit 6 in Long-Term Regional Transmission Planning is necessary because Long-Term Regional Transmission Facilities could result in reduced production costs and reduced loss of load (or reduced emergency procurements necessary to support the system), including reductions due to increased Interregional Transfer Capability, and improved performance during extreme weather events and unexpected system conditions. Further, the benefit of mitigation of high production costs resulting from extreme weather events and unexpected system conditions can be economically significant. A relatively few numbers of hours could represent a large share of the total benefit of reduced congestion costs that a Long-Term Regional Transmission Facility provides.¹⁷⁸⁴ We also find that it is critical for transmission providers to measure and use Benefit 6 given that extreme weather events and unexpected system conditions have significantly and increasingly affected the reliable operation of the electric grid. As the Commission has previously noted, extreme weather events have occurred with greater frequency in recent years, leading to load shed events that present an unacceptable risk to life and have an

extreme economic impact.¹⁷⁸⁵ By requiring the use of Benefit 6, we ensure that transmission providers measure and use the benefit of Long-Term Regional Transmission Facilities under these conditions when performing Long Term Regional Transmission Planning. Further, by requiring use of Benefit 6, we enable transmission providers to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

802. Regarding the first modification listed above, we require transmission providers to measure, as part of Benefit 6, reduced loss of load (or reduced emergency energy procurement to avoid loss of load), not only reduced production costs. We find it necessary to include reduced loss of load because Long-Term Regional Transmission Facilities can provide benefits by improving reliability during extreme weather events and unexpected system conditions,¹⁷⁸⁶ which can be significant given the high cost and risk to life during periods with insufficient generation to meet system load. An example of how a reduction in loss of load could be measured is by quantifying the reduction in expected unserved energy but for the Long-Term Regional Transmission Facility during an extreme weather event or unexpected system conditions, determining the value of lost load, and multiplying these two values to obtain a monetary value.¹⁷⁸⁷

803. We note that Benefit 6 is distinct from other benefits that we require transmission providers to measure and use, because transmission providers must model different system conditions (extreme weather events and unexpected system conditions) when measuring Benefit 6. Specifically, Benefit 2(a) measures reduced loss of load probability in the context of the system conditions used for resource adequacy planning, which typically includes consideration of normal system conditions and may vary by region. In contrast, Benefit 6 measures reduced loss of load for specific extreme weather events and unexpected system conditions identified by the

transmission providers.¹⁷⁸⁸

Additionally, while Benefit 3 and Benefit 6 both measure production cost savings, the system conditions used to measure Benefit 6 can include higher electricity demand, volatile production costs, and a more expansive set of generation outages, such as unplanned generation outages due to extreme weather. Similarly, Benefit 5 and Benefit 6 both measure the benefits of reduced congestion due to transmission outages; however, the system conditions used to measure Benefit 6 include a more expansive set of transmission outages, such as unplanned transmission outages due to extreme weather.

804. Regarding the second modification listed above, we require transmission providers, as part of Benefit 6, to account for mitigation of unexpected system conditions during periods when transmission facilities have particularly high value, not only during extreme weather events. We recognize that unexpected system conditions can create periods when Long-Term Regional Transmission Facilities have particularly high value because of, for example, generator and/or transmission outages, extreme or volatile production costs, and generation and/or load forecast errors.¹⁷⁸⁹ Limited resource availability, or limited system flexibility, can make

¹⁷⁸⁸ Benefit 2(b), which measures the benefit of reduced planning reserve margin, is also used in the context of resource adequacy planning. We do not allow transmission providers to measure Benefit 6 in terms of reduced planning reserve margin because system planners do not always model extreme weather events or unexpected system conditions when establishing the planning reserve margin used for resource adequacy purposes. In contrast, reduced loss of load can be measured for any system condition, even those conditions that are not used for resource adequacy planning.

¹⁷⁸⁹ See, e.g., ACEG Initial Comments at 42–45 (citing Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System* (Oct. 14, 2020), <https://open.bu.edu/handle/2144/41451>; The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, 2, 34, 78, 85–86, 99 (2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-TransmissionPlanning-Report_v2.pdf); DC and MD Offices of People's Counsel Initial Comments at 28 (citing Pfeifenberger, Ruiz, Van Horn, *The Value of Diversifying Uncertain Renewable Generation through the Transmission System*, BU-ISE (Oct. 14, 2020), <https://open.bu.edu/handle/2144/41451>); US Senator Schumer Supplemental Comments at 2–3 (citing Millstein et al., Lawrence Berkeley National Laboratory, *The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade*, 3–6 (Feb. 2023), https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvaluefact_sheet-2022update-20230203.pdf); US Senator Whitehouse Supplemental Comments at 2 (referencing outages related to extreme events having costs, including economic costs of in the billions of dollars from elevated energy costs).

¹⁷⁸³ Throughout this final order, “Benefit 6” refers to “Final Order Benefit 6” unless preceded by “NOPR.”

¹⁷⁸⁴ E.g., ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33).

¹⁷⁸⁵ See Order No. 896, 183 FERC ¶ 61,191 at P 2; Order No. 897, 183 FERC ¶ 61,192 at PP 21–22.

¹⁷⁸⁶ PJM Initial Comments at 94; MISO Initial Comments at 12–13; Order No. 897, 183 FERC ¶ 61,192 at PP 6–12.

¹⁷⁸⁷ E.g., MISO, *L RTP Tranche 2 Business Case Benefit Metrics*, 6–7 (Aug. 31, 2023), <https://cdn.misoenergy.org/20230831%20L RTP%20Workshop%20Item%2002%20Business%20Case%20Metrics%20Development630034.pdf>.

it challenging for system operators to immediately address these unexpected system conditions, and Long-Term Regional Transmission Facilities that provide benefits under Benefit 6 will equip system operators with more options to manage the worst-case outcomes. These high-value periods of unexpected system conditions, while infrequent and not necessarily during extreme weather events, may account for a large share of the potential value of a Long-Term Regional Transmission Facility.¹⁷⁹⁰ We require transmission providers to account for circumstances that contribute to these infrequent and high-value periods specific to their transmission planning region when measuring Benefit 6. Transmission providers may, for example, identify historical periods when significant transmission congestion was due to certain conditions (e.g., generators being unavailable due to a forecast error), then model those conditions in each Long-Term Scenario.¹⁷⁹¹ Therefore, we require transmission providers to use not only information from modeling extreme weather events but also information from additional modeling that accounts for unexpected system conditions, as part of Benefit 6. To avoid double-counting of similar circumstances, transmission providers must account for extreme weather events and unexpected system conditions that are separate and distinct such that the benefits of mitigating each system condition can be combined into a single benefit measure.

805. Finally, we require transmission providers to measure, as part of Benefit 6, the benefits associated with any increase in Interregional Transfer Capability that a Long-Term Regional Transmission Facility would provide during an extreme weather event and unexpected system conditions that results in multiple concurrent and sustained generation and/or transmission outages. As discussed above, we find that Long-Term Regional Transmission Facilities can increase Interregional Transfer Capability by changing the topology of the

transmission system.¹⁷⁹² Further, we find that the benefits of mitigating extreme weather events and unexpected system conditions due to increased Interregional Transfer Capability provided by Long-Term Regional Transmission Facilities can be significant.¹⁷⁹³ To comply with this requirement, transmission providers must include in the modeling they use to measure Benefit 6 any increase in Interregional Transfer Capability that a Long-Term Regional Transmission Facility would provide during an extreme weather event and unexpected system conditions that results in multiple concurrent and sustained generation and/or transmission outages.

806. To account for extreme weather events as part of Benefit 6, transmission providers may incorporate information from the sensitivity they must develop and apply to each Long-Term Scenario that includes multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area.¹⁷⁹⁴ We reiterate that we require transmission providers to measure the required benefits under each Long-Term Scenario. However, in the case of Benefit 6, transmission providers may measure the benefit of mitigating extreme weather events using the required extreme weather event sensitivity applied to each Long-Term Scenario; we do not require them to separately measure the benefit of mitigating extreme weather events in each scenario without applying that sensitivity.¹⁷⁹⁵

¹⁷⁹² *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Sensitivities for High-Impact, Low-Frequency Events section.

¹⁷⁹³ ACEG Initial Comments at 5; ACEG Reply Comments at 3–5; BP Initial Comments at 10; Breakthrough Energy Initial Comments at 2; Clean Energy Associations Initial Comments at 5, 21; Kansas Corporation Commission Initial Comments at 8–9; NARUC Initial Comments at 23; US DOE Initial Comments at 39–42.

¹⁷⁹⁴ *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Sensitivities for High-Impact, Low-Frequency Events section (stating transmission providers must develop at least one sensitivity, applied to each Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area). Transmission providers may also incorporate analyses from an Extreme Weather Vulnerability Assessment as generally described in Order No. 897.

¹⁷⁹⁵ We recognize that transmission providers may not use an extreme weather event sensitivity that includes system conditions that allow transmission providers to measure the benefit of mitigating unexpected system conditions in every Long-Term Scenario. In such cases, transmission providers must measure the benefit of mitigating unexpected system conditions in each Long-Term

807. Consistent with all other benefits that we require transmission providers to measure, we do not require a standardized method for measuring Benefit 6 subject to measuring the components described above.¹⁷⁹⁶ As the Commission stated in the NOPR, there are different approaches to calculating components of this benefit,¹⁷⁹⁷ and this final order provides transmission providers with flexibility in developing the method that they will use to measure this benefit.

808. We disagree with commenters who express general concerns regarding the difficulty of measuring this benefit.¹⁷⁹⁸ In the NOPR, the Commission identified studies that measured benefits of a transmission facility in a manner similar to the requirements in Benefit 6.¹⁷⁹⁹ Because we allow flexibility as far as the method transmission providers use to measure each benefit included in the required set of benefits, including Benefit 6, we believe that transmission providers should be able to tailor a method for measuring Benefit 6 that fits their circumstances. Further, transmission providers can build on methods that they use to measure the other benefits required by this final order to measure Benefit 6. For example, transmission providers can use the same method to measure reduced production costs in accordance with Benefit 6 as they do to measure Benefit 3, Production Costs Savings, but modify the model inputs to capture reduced production costs during extreme weather events and unexpected system conditions. Moreover, we recognize that there is a balance between requiring transmission providers to measure the benefits of Long-Term Regional Transmission Facilities that are most readily measured and ensuring that transmission providers are appropriately capturing the value of Long-Term Regional Transmission Facilities when evaluating them for selection. Even to the extent to which Benefit 6 may be more difficult to measure than the other benefits that

Scenario even without an extreme weather event sensitivity applied to those scenarios or must apply a separate sensitivity that allows for the measurement of Benefit 6 to each Long-Term Scenario.

¹⁷⁹⁶ E.g., ACEG Initial Comments at 42–44; DC and MD Offices of People's Counsel Initial Comments at 26–27.

¹⁷⁹⁷ NOPR, 179 FERC ¶ 61,028 at P 207 (providing examples of CAISO's analysis of Devers-Palo Verde Line No. 2, ATC's production cost simulation analysis of insurance benefits for the ATC Paddock-Rockdale transmission line, and a Grid Strategies study).

¹⁷⁹⁸ NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; West Virginia Commission Supplemental Comments at 4.

¹⁷⁹⁹ NOPR, 179 FERC ¶ 61,028 at PP 207, 209.

¹⁷⁹⁰ LBNL Aug. 2022 Transmission Value Study at 33 (stating that the majority of transmission value estimated occurs during "extreme" conditions that fall outside of the 171 designated extreme weather event days between 2012 and 2021); Millstein et al., Lawrence Berkeley National Laboratory, *The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade*, 3–6 (Feb. 2023), <https://eta-publications.lbl.gov/sites/default/files/lbnl-transmissionvalue-fact-sheet-2022update-20230203.pdf>.

¹⁷⁹¹ Alternatively, transmission providers may, for example, use probabilistic transmission planning methods to account for infrequent and high-value periods.

we require, we nonetheless find that requiring transmission providers to measure Benefit 6 is necessary because Benefit 6 is significant.¹⁸⁰⁰

809. We are unpersuaded by general arguments that transmission providers should not consider this benefit because it varies by transmission planning region or it only accrues to certain entities.¹⁸⁰¹ We are not requiring transmission providers to model a specific extreme weather event or unexpected system condition; transmission providers may decide what extreme weather event and unexpected system conditions to model, allowing them to ensure that the conditions modeled are relevant to circumstances in their transmission planning region. In response to NRECA's argument that this benefit requires subjective judgement,¹⁸⁰² we conclude that transmission providers have sufficient expertise to identify and model extreme weather events and unexpected system conditions when evaluating Long-Term Regional Transmission Facilities.¹⁸⁰³ In response to AEP's argument that NOPR Benefit 7 (mitigation of weather and load uncertainty) is of lesser importance compared to other benefits described in the NOPR and should be optional for transmission providers to measure and use,¹⁸⁰⁴ we disagree because the evidence in the record demonstrates that Final Order Benefit 6 (which includes NOPR Benefit 7) is significant.¹⁸⁰⁵

810. NARUC states that the benefit of mitigation of extreme weather events may need to be more fully considered only in large transmission planning regions or in interregional transmission planning.¹⁸⁰⁶ Although transmission providers could also consider the benefits of mitigation of extreme weather events as part of interregional transmission coordination, we believe transmission providers can measure and use the benefit of mitigation of extreme weather events in regional transmission planning processes regardless of the size of the transmission planning region, because extreme weather events can occur and affect the transmission system in any region. If the size of the extreme weather event is larger than the transmission planning region,

transmission providers can consider the extent to which they can rely on interregional flows from other transmission planning regions during the extreme weather event. We note that transmission providers in each transmission planning region must coordinate and share information with the transmission providers in each neighboring transmission planning region and must identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address Long-Term Transmission Needs, as described in more detail in the Interregional Transmission Coordination section of this final order. Better measurement of the benefits of mitigation of extreme weather events as part of regional transmission planning can only help facilitate such efforts. We encourage transmission providers in neighboring transmission planning regions to share information with one another that would be useful to measure Benefit 6 more accurately through their interregional transmission coordination procedures.

811. Some commenters state that the benefits of mitigation of extreme events and system contingencies and mitigation of weather and load uncertainty overlap, or should be combined.¹⁸⁰⁷ We note that Benefit 6, as described above, modifies and combines the benefits proposed in the NOPR of (1) mitigation of extreme events and system contingencies and (2) mitigation of weather and load uncertainty, which should address concerns of separately requiring transmission providers to use two similar benefits that some argue could overlap.

vii. Final Order Benefit 7: Capacity Cost Benefits From Reduced Peak Energy Losses

(a) NOPR Description

812. The Commission described this benefit, NOPR Benefit 8 (renumbered in this final order as Final Order Benefit 7), in the NOPR as reduced generation capacity investment needed to meet peak load.¹⁸⁰⁸ The Commission noted that capacity cost savings from reduced peak energy losses benefits refer to the ability of proposed transmission facilities to lessen the amount of transmission system energy losses during peak-load conditions which, over time, would decrease the need for new generation capacity installations or purchases. To the extent that new transmission facilities result in changes

to generation dispatch and flows, transmission system energy losses will also change. If transmission system losses are reduced via the new transmission facilities, transmission providers will not have to construct or procure additional generation to satisfy installed capacity requirements for peak-load conditions. If there is a reduction in energy losses during peak conditions, this would result in, presumably, lowered investments for generation capacity resources to meet the peak load. For example, Entergy found that potential transmission facilities in its footprint could reduce peak-load transmission losses and associated needed generation investment by 2% of total transmission facility costs.¹⁸⁰⁹ The Commission noted that capacity cost savings from reduced peak energy losses only attempt to evaluate benefits for peak-load conditions.

813. The Commission stated that one potential way to calculate capacity cost savings from reduced peak energy losses is to calculate the present value of capital cost savings associated with the reduction in installed generation requirements.¹⁸¹⁰ To arrive at the value of associated capital cost savings, the estimated net cost of new entry (Net CONE) (*i.e.*, the cost of new peaking generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource constrained) would be multiplied by the reduction in installed generation capacity requirements. The resulting value would represent the avoided cost of procuring more generation to cover transmission system losses during peak-load conditions that would be passed on to consumers via lowered generation capacity costs.¹⁸¹¹

(b) Comments

814. A number of commenters support mandating consideration of NOPR Benefit 8.¹⁸¹² ACEG and DC and

¹⁸⁰⁹ *Id.* P 211 & n.346 (citing ITC, Joint Application, Docket No. EC12-145-000, Ex. ITC-600 (Testimony of Pfeifenberger), at 77-78 (filed Sept. 24, 2012)).

¹⁸¹⁰ *Id.* P 212.

¹⁸¹¹ *Id.*

¹⁸¹² Acadia Center and CLF Initial Comments at 21-22; ACEG Initial Comments at 32, 45; ACORE Initial Comments at 12; AEE Reply Comments at 25; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21-22; Clean Energy Associations Initial Comments at 18-20; DC and MD Offices of People's Counsel Initial Comments at 20; ENGIE Reply Comments at 2-3; Hannon Armstrong Initial Comments at 2-3; Interwest Initial Comments at 12-14; National and State Conservation Organizations Initial Comments at 1; Pine Gate Initial Comments at 34-37; PIOs Initial Comments at 37-38; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50.

¹⁸⁰⁰ *Supra* P 797.

¹⁸⁰¹ Louisiana Commission Initial Comments at 18-19; Pacific Northwest Utilities Initial Comments at 9.

¹⁸⁰² NRECA Initial Comments at 45.

¹⁸⁰³ NESCOE Initial Comments at 42.

¹⁸⁰⁴ AEP Initial Comments at 27.

¹⁸⁰⁵ *Supra* note 1769; *see also* ACORE Initial Comments at 11 (citing LBNL Aug. 2022 Transmission Value Study at 33).

¹⁸⁰⁶ NARUC Initial Comments at 21, 23.

¹⁸⁰⁷ MISO Initial Comments at 51; PJM Initial Comments at 94.

¹⁸⁰⁸ NOPR, 179 FERC ¶ 61,028 at P 210.

MD People's Counsel state that NOPR Benefit 8 is a distinct benefit category that has been measured before.¹⁸¹³ PIOs state that SPP quantified NOPR Benefit 8 in its 2016 Regional Cost Allocation Review and that "leav[ing] these cost savings on the cutting room floor will ultimately raise costs for consumers and result in an inefficient transmission plan."¹⁸¹⁴

815. Other commenters, such as NARUC, oppose mandating consideration of NOPR Benefit 8. NARUC contends that this benefit is a subset of the lowered system reserve margins benefit. NARUC states that NOPR Benefit 8 is unlikely to occur within organized, competitive generation markets because additional transmission will not deter the installation of new generation under current Federal open access policies. However, NARUC argues, this benefit may be attainable in transmission planning regions served by vertically integrated utilities where transmission can substitute for new generation construction. NARUC asserts that hundreds of thousands of megawatts of generation currently await interconnection studies in the various RTOs/ISOs and non-RTO/ISO transmission planning regions, and it is difficult to see how construction of new transmission facilities can remove any of this demand for additional generator interconnection.¹⁸¹⁵

816. West Virginia Commission also opposes a requirement to use NOPR Benefit 8, arguing that the calculation requires significant evidence based on assumptions that are difficult, if not impossible, to quantify before the fact.¹⁸¹⁶

(c) Commission Determination

817. As an initial matter, we renumber NOPR Benefit 8 and refer to it in this determination section as Final Order Benefit 7. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to measure and use Final Order Benefit 7, Capacity Cost Benefits from Reduced

Peak Energy Losses, in Long-Term Regional Transmission Planning. We adopt the NOPR's proposed description of Final Order Benefit 7 as reduced generation capacity investment needed to meet peak load.¹⁸¹⁷ We find that requiring the use and measurement of Final Order Benefit 7, as described, is necessary to ensure that capacity cost benefits from reduced peak energy losses are not excluded from Long-Term Regional Transmission Planning because standard production cost modeling and the other benefits that this final order requires transmission providers to measure and use will not capture this benefit. Absent a requirement for transmission providers to measure and use Final Order Benefit 7 in Long-Term Regional Transmission Planning, transmission providers may not identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.

818. One potential way to measure capacity cost savings from reduced peak energy losses is to calculate the present value of capital cost savings associated with the reduction in installed generation requirements. To arrive at the value of capital cost savings, the estimated net cost of new entry (*i.e.*, the cost of new peaking generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource constrained) could be multiplied by the reduction in installed generation capacity requirements. The resulting value would represent the avoided cost of procuring more generation to cover transmission system losses during peak-load conditions, savings that would be passed on to customers via lowered generation capacity costs.

819. We disagree with NARUC's contention that this benefit is a subset of the lowered system reserve margins benefit and that it is unlikely to occur within organized, competitive generation markets.¹⁸¹⁸ ACEG and DC and MD People's Counsel both indicate that Final Order Benefit 7 is a distinct benefit category that has been measured before, citing MISO's Multi-Value Project portfolio, among other examples of its use, which measures capacity cost savings from reduced peak energy losses as an independent benefit.¹⁸¹⁹ While we

acknowledge that this benefit may have the effect of lowering system reserve margins, we agree with PIOs that these cost savings are distinct from Benefit 2 and that failing to specifically evaluate potential cost savings related to reduced peak energy losses may result in higher capacity costs and relatively inefficient or less cost-effective transmission development. As discussed above, Benefit 2 recognizes potential cost savings of providing additional pathways for connecting generation resources with load. Here, we are assessing the benefits of limiting transmission losses along those pathways. We also note that this approach is consistent with Benefits 3 and 4 above that separately recognize potential cost savings associated with lower production costs and reduced transmission energy losses in energy markets. In light of the evidence that multiple transmission providers have successfully measured this benefit, as well as the example that we provide above describing how a transmission provider may be able to calculate this benefit, we further disagree with West Virginia Commission's argument that calculation of this benefit is based on assumptions that are difficult to quantify in advance.

viii. Other Benefits

(a) Comments

820. Numerous commenters address in various ways the other five benefits that the Commission described in the NOPR but that we do not require transmission providers to measure and use in Long-Term Regional Transmission Planning in this final order: mitigation of weather and load uncertainty,¹⁸²⁰ deferred generation capacity investments, access to lower cost generation, increased competition, and increased market liquidity.¹⁸²¹

145–000, Ex. ITC–600 (Testimony of Pfeifferberger), at 77–78 (filed Sept. 24, 2012); SPP, SPP Priority Projects Phase II Report, Rev. 1, April 27, 2010, at 26; ATC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137–CE–149, PSC Reference # 75598), at 4, 63; and MISO, Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, at 25, 27)).

¹⁸²⁰ We note that elements of this benefit are now contained in Benefit 6, the description of which has been revised from the NOPR.

¹⁸²¹ Acadia Center and CLF Initial Comments at 21–22; ACEG Initial Comments at 32, 45–48; ACORE Initial Comments at 12; AEE Reply Comments at 25; AEP Initial Comments at 25–27; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–22; Clean Energy Associations Initial Comments at 18–20; DC and MD Offices of People's Counsel Initial Comments at 20, 28–30; ENGIE Reply Comments at 2–3; Hannon Armstrong Initial Comments at 2–3; Idaho Power Initial Comments at 7–8; Interwest Initial

¹⁸¹³ ACEG Initial Comments at 48; DC and MD People's Counsel Initial Comments at 28 (both citing ITC, Joint Application, Docket No. EC12–145–000, Ex. ITC–600 (Testimony of Pfeifferberger), at 77–78 (filed Sept. 24, 2012); SPP, SPP Priority Projects Phase II Report, Rev. 1, April 27, 2010, at 26; ATC, Planning Analysis of the Paddock-Rockdale Project, April 5, 2007 (filed in PSCW Docket 137–CE–149, PSC Reference # 75598), at 4, 63; and MISO, Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop, August 22, 2011, at 25, 27)).

¹⁸¹⁴ PIOs Initial Comments at 42.

¹⁸¹⁵ NARUC Initial Comments at 24.

¹⁸¹⁶ West Virginia Commission Supplemental Comments at 4.

¹⁸¹⁷ We note that in the NOPR, this benefit was designated as Benefit 8. We have revised the ordering designation of this benefit in this final order.

¹⁸¹⁸ NARUC Initial Comments at 24.

¹⁸¹⁹ ACEG Initial Comments at 48; DC and MD People's Counsel Initial Comments at 28 (both citing ITC, Joint Application, Docket No. EC12–

Other commenters address in various ways benefits not listed in the NOPR for transmission providers to consider for use in evaluating Long-Term Regional Transmission Facilities.¹⁸²²

(b) Commission Determination

821. We decline to require transmission providers to measure and use the remaining five benefits described in the NOPR in Long-Term Regional Transmission Planning (*i.e.*, mitigation of weather and load uncertainty, generation capacity investments, access to lower-cost generation, increased competition, and increased market liquidity). We find that the required set of benefits that we adopt herein is a sufficiently broad range of benefits to ensure that transmission providers are identifying, evaluating, and selecting Long-Term Regional Transmission Facilities that more efficiently or cost-effectively

Comments at 12–14; ISO-NE Initial Comments at 34; Joint Consumer Advocates Initial Comments at 11–12; MISO Initial Comments at 50–51; NARUC Initial Comments at 21, 24–25; National and State Conservation Organizations Initial Comments at 1; New Jersey Commission Initial Comments at 11–14; North Carolina Commission and Staff Initial Comments at 6–7; NRECA Initial Comments at 45; Pacific Northwest Utilities Initial Comments at 9; Pine Gate Initial Comments at 34–37; PIOs Initial Comments at 37–38; PJM Initial Comments at 94; PJM Market Monitor Initial Comments at 5–6; PPL Initial Comments at 13–15; RMI Initial Comments at 1; SEIA Initial Comments at 16; Southeast PIOs Initial Comments at 50; Southeast PIOs Reply Comments at 27–28; Southern Initial Comments at 25–27; West Virginia Commission Supplemental Comments at 4; US DOE Initial Comments at 31–32.

¹⁸²² ACEG Initial Comments at 6–8; AEE Reply Comments at 25–26; AEP Initial Comments at 6, 23–27; Amazon Initial Comments at 5; Breakthrough Energy Initial Comments at 21–23; California Commission Initial Comments at 31–34; California Energy Commission Initial Comments at 3; CARE Coalition Initial Comments at 32–33; Certain TDUs Reply Comments at 1–3; Clean Energy Associations Initial Comments at 19–20; Clean Energy Buyers Initial Comments at 20–21; Clean Energy States Initial Comments at 6–8; DC and MD Offices of People's Counsel Initial Comments at 18–19; Entergy Initial Comments at 21; Environmental Groups Supplemental Comments at 2–3; Grand Rapids NAACP Initial Comments at 21–23; GridLab Initial Comments at 25–28; Interwest Initial Comments at 13–14; ITC Initial Comments at 21–22; Joint Consumer Advocates Initial Comments at 11–12; Large Public Power Initial Comments at 28–29; Michigan Commission Initial Comments at 7; Nevada Commission Initial Comments at 10–11; Northwest and Intermountain Initial Comments at 15–16; NYISO Initial Comments at 39; Pattern Energy Reply Comments at 8–9; PIOs Initial Comments at 43–44; PIOs Reply Comments at 7–8; PJM Initial Comments at 94–96; Policy Integrity Initial Comments at 28; Policy Integrity Supplemental Comments at 4–8; PPL Initial Comments at 14–15; R Street Initial Comments at 9–10; Rail Electrification Initial Comments at 6–7; RMI Initial Comments at 2; SEIA Initial Comments at 16–17; Shell Initial Comments at 14–16; Tabors Caramanis Rudkevich Initial Comments at 6; US DOE Initial Comments at 33–34; Vistra Initial Comments at 15–16; WE ACT Initial Comments at 2–3.

address Long-Term Transmission Needs. As such, we find that the measurement and use of additional benefits in Long-Term Regional Transmission Planning is not necessary to ensure that rates remain just and reasonable.

822. However, we recognize that Long-Term Regional Transmission Facilities may provide additional benefits that may merit consideration when transmission providers are identifying, evaluating, and selecting such facilities to address Long-Term Transmission Needs more efficiently or cost-effectively. Therefore, transmission providers may measure and use additional benefits beyond those included in the required set of benefits in Long-Term Regional Transmission Planning, including on a transmission facility or plan-specific basis, subject to the requirement that they do so in a manner that is consistent with their obligations under Order No. 890 and Order No. 1000 transmission planning principles to be open and transparent as to their transmission planning processes.

3. Identification, Measurement, and Evaluation of the Benefits of Long-Term Regional Transmission Facilities

a. NOPR Proposal

823. The Commission proposed to require transmission providers in each transmission planning region to identify on compliance the benefits that they will use in Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. The Commission proposed that as part of this compliance obligation, transmission providers would be required to explain the rationale for using the benefits identified.¹⁸²³

b. Comments

824. Many commenters support requiring identification of, and transparency regarding, the benefits that transmission providers will use in Long-Term Regional Transmission Planning.¹⁸²⁴ For example, Nebraska

¹⁸²³ NOPR, 179 FERC ¶ 61,028 at P 183.

¹⁸²⁴ APPA Initial Comments at 5; Avangrid Initial Comments at 7, 29; Business Council for Sustainable Energy Initial Comments at 5; California Commission Initial Comments at 28–30; California Energy Commission Initial Comments at 3; ENGIE Reply Comments at 3; Handy Law Initial Comments at 8; Massachusetts Attorney General Initial Comments at 3; Michigan Commission Initial Comments at 6; Nebraska Commission Initial

Commission states that the NOPR proposal will foster the necessary flexibility to accommodate varying needs and approaches of different transmission planning regions.¹⁸²⁵

825. Certain TDUs and Michigan Commission state that transmission providers must clearly articulate their methods for calculating identified benefits.¹⁸²⁶ Certain TDUs further state that benefits should be evaluated with consistent reference cases to ensure consistency across scenarios.¹⁸²⁷ Certain TDUs and Entergy state that transmission providers should incorporate their benefit calculation methods, as well as, according to Entergy, their role in selection, into the OATT.¹⁸²⁸ Entergy argues that the Commission should allow transmission providers to use different benefits on a regional or subregional level, but that benefits should not change from one transmission project or portfolio to the next without an OATT amendment.¹⁸²⁹

826. MISO TOs state that MISO already meets the NOPR's proposed requirement to identify benefits used in Long-Term Regional Transmission Planning and explain how they will be calculated.¹⁸³⁰

827. Some commenters express concerns with the Commission's proposed benefit identification requirement,¹⁸³¹ including concerns over perceived excessive quantification¹⁸³² or requirements to calculate benefits individually.¹⁸³³ Duke asserts that the Commission should

Comments at 7; NESCOE Initial Comments at 44 (citing NOPR, 179 FERC ¶ 61,028 at PP 183, 186); NRECA Initial Comments at 46; NYISO Initial Comments at 37–38; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 7; Vermont State Entities Initial Comments at 6.

¹⁸²⁵ Nebraska Commission Initial Comments at 7.

¹⁸²⁶ Certain TDUs Initial Comments at 13;

Michigan Commission Initial Comments at 6.

¹⁸²⁷ Certain TDUs Initial Comments at 13–14.

¹⁸²⁸ Certain TDUs Initial Comments at 14–15; Entergy Reply Comments at 4–5 (citing *City & Cnty. of San Francisco v. FERC*, 24 F.4th 652, 661 (D.C. Cir. 2022); *Sw. Power Pool, Inc.*, 180 FERC ¶ 61,074, at PP 24–31 (2022), *order on reh'g and setting aside*, 182 FERC ¶ 61,100 (2023)).

¹⁸²⁹ Entergy Reply Comments at 5.

¹⁸³⁰ MISO TOs Initial Comments at 19–22 (citing MISO, Electric Tariff, attach. FF §§ II.C.2, II.C.5; MISO, *LRTTP Tranche 1 Portfolio Detailed Business Case*, at 15–49, 60 (June 25, 2022), <https://cdn.misoenergy.org/LRTTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf>).

¹⁸³¹ DC and MD Offices of People's Counsel Initial Comments at 19; Duke Initial Comments at 24; EEI Initial Comments at 20; Entergy Initial Comments at 22; Illinois Commission Initial Comments at 13–14; Louisiana Commission Initial Comments at 18; Michigan Commission Initial Comments at 6; US Chamber of Commerce Initial Comments at 7–8. Further detail on the basis for these commenters' concerns is provided *infra*.

¹⁸³² See, e.g., Duke Initial Comments at 24.

¹⁸³³ See, e.g., EEI Initial Comments at 20.

clarify that it will not force transmission providers to assign dollar values for every benefit because some benefits' quantification is subjective.¹⁸³⁴ EEI asserts that transmission providers should not have to calculate all of the benefits for a transmission project but states that those benefits used for cost allocation purposes should be quantifiable.¹⁸³⁵ NYISO requests that the final order confirm that it does not prescribe how benefits must be calculated and, more specifically, that transmission providers are not required to calculate the listed benefits in the exact manner described in the NOPR.¹⁸³⁶

828. MISO notes that the benefits it currently uses in regional transmission planning are not all specified in the Tariff itself but were developed as part of the review process with MISO stakeholders. MISO adds that the flexibility to look for relevant benefits and apply them in long-term planning scenarios is important in the process to identify long-term regional solutions that reflect the needs and value-drivers of the MISO footprint.¹⁸³⁷ MISO states that if limited to a prescriptive set of benefits, MISO may not be in the same position to move forward the transmission projects of the greatest benefit and value to MISO and its stakeholders.¹⁸³⁸

829. Some commenters opine on requirements or best practices for identifying, measuring, and combining benefits.¹⁸³⁹ For example, some commenters comment on the measurement and/or calculation of benefits.¹⁸⁴⁰ Entergy argues that the

Commission should require all benefits to be reasonably achievable in real-time operations.¹⁸⁴¹ SPP Market Monitor states that assumptions into benefit calculations should be improved to ensure that they result in just and reasonable rates.¹⁸⁴² Large Public Power emphasizes that the Commission should clarify that benefits must reflect load-serving entities' actual use of proposed transmission facilities, measured by anticipated power flows.¹⁸⁴³

830. SEIA suggests that there are many resources to inform methods for the calculation of benefits, including MISO's Long Range Transmission Plan Tranche 1 portfolio.¹⁸⁴⁴ Also referencing MISO's process, AEP contends that the benefits of regional transmission facilities should be evaluated collectively, through a multi-value analysis, and cites MISO's existing process as an example.¹⁸⁴⁵

831. Some commenters opine on the need for quantification and/or specificity of benefits.¹⁸⁴⁶ DC and MD Offices of People's Counsel assert that any benefit used should be pre-defined and its measurement accurate and transparent.¹⁸⁴⁷ PIOs also state that the Brattle-Grid Strategies Oct. 2021 Report provides evidence that benefits from transmission facilities are not difficult to quantify despite claims to the contrary.¹⁸⁴⁸ NASUCA asserts that the methods for calculating and assigning benefits should be based on objective, measurable, clear, and specific metrics.¹⁸⁴⁹ Similarly, Illinois Commission, Pacific Northwest Utilities, and NARUC assert that transmission benefits must be verifiable and quantifiable.¹⁸⁵⁰

832. A few commenters address the ease of quantification of the benefits listed in the NOPR. NARUC states that

NOPR Benefits 1–5 and 8–10 seem somewhat capable of quantification.¹⁸⁵¹ NRECA asserts that the benefits at the top of the list in the NOPR are reasonably quantifiable, while those farther down the list require more subjective judgements.¹⁸⁵² APPA agrees that some of the benefits listed in the NOPR would be more challenging to quantify and therefore would be more difficult to justify as a just and reasonable way to allocate costs.¹⁸⁵³

833. Some commenters support the use of benefit-cost analysis frameworks.¹⁸⁵⁴ Michigan State Entities express that having a prescribed benefit-cost analysis framework can help ensure appropriate quantification of benefits, adding that there is less transparency when individual transmission providers may determine how these benefits stack up against each other.¹⁸⁵⁵ Therefore, Michigan State Entities recommend that the Commission adopt the cost-benefit analysis framework already used throughout the Federal Government. According to Michigan State Entities, the Commission's legal authority to do so is well-established by court decisions and it would help to ensure sufficient regional transmission cooperation to achieve just and reasonable rates.¹⁸⁵⁶

834. Six Cities argues that transmission planning should assess both project benefits and costs.¹⁸⁵⁷ Vermont State Entities agree that a comprehensive benefit-cost analysis would lead to better and more cost-effective transmission planning.¹⁸⁵⁸ Southern also states that the burdens associated with proposed transmission projects should be recognized, including not only immediate cost and rate impacts, but also effects on local communities and landowners and issues of equity and environmental justice.¹⁸⁵⁹

835. Likewise, certain commenters state that they support the adoption of benefit-cost analysis using quantifiable, replicable, non-duplicative, and forward-looking metrics.¹⁸⁶⁰ US

¹⁸³⁴ Duke Initial Comments at 24.

¹⁸³⁵ EEI Initial Comments at 20.

¹⁸³⁶ NYISO Initial Comments at 36–40.

¹⁸³⁷ MISO Initial Comments at 9–10.

¹⁸³⁸ *Id.* at 9.

¹⁸³⁹ Acadia Center and CLF Initial Comments at 23; ACORE Reply Comments at 3; AEP Initial Comments at 32; AEP Initial Comments at 21–24; APPA Initial Comments at 32; City of New Orleans Council Initial Comments at 11; Clean Energy Associations Initial Comments at 20–21; DC and MD Offices of People's Counsel Initial Comments at 19; Duke Initial Comments at 24; EEI Initial Comments at 20; Entergy Initial Comments at 22; Illinois Commission Initial Comments at 13–14; Large Public Power Initial Comments at 28; Louisiana Commission Initial Comments at 18; Michigan State Entities Initial Comments at 5–7; NARUC Initial Comments at 20–26; NASUCA Initial Comments at 10; NRECA Initial Comments at 45; NYISO Initial Comments at 37; PJM Market Monitor Initial Comments at 4; SEIA Initial Comments at 18–19; Six Cities Initial Comments at 2–3; Southern Initial Comments at 31; SPP Market Monitor Initial Comments at 11; US Chamber of Commerce Initial Comments at 7–8; US DOE Initial Comments at 31; Vermont State Entities Initial Comments at 6.

¹⁸⁴⁰ AEP Initial Comments at 21–24; Clean Energy Associations Initial Comments at 21; Large Public Power Initial Comments at 28; SEIA Initial

Comments at 18–19; SPP Market Monitor Initial Comments at 11.

¹⁸⁴¹ Entergy Initial Comments at 22.

¹⁸⁴² SPP Market Monitor Initial Comments at 11.

¹⁸⁴³ Large Public Power Initial Comments at 28.

¹⁸⁴⁴ SEIA Initial Comments at 18–19 (citing Rob Gramlich, *Enabling Low-Cost Clean Energy & Reliable Service Through Better Transmission Benefits Analysis*, at 17, <https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf>).

¹⁸⁴⁵ AEP Initial Comments at 21–24.

¹⁸⁴⁶ ACORE Reply Comments at 3 (citing US DOE Initial Comments at 31); Concerned Scientists Reply Comments at 8–10; DC and MD Offices of People's Counsel Initial Comments at 19; Entergy Initial Comments at 22; NASUCA Initial Comments at 10; US DOE Initial Comments at 31.

¹⁸⁴⁷ DC and MD Offices of People's Counsel Initial Comments at 19.

¹⁸⁴⁸ PIOs Initial Comments at 42–44.

¹⁸⁴⁹ NASUCA Initial Comments at 10.

¹⁸⁵⁰ Illinois Commission Initial Comments at 13–14; NARUC Initial Comments at 20–25; Pacific Northwest Utilities Initial Comments at 8–9.

¹⁸⁵¹ NARUC Initial Comments at 21.

¹⁸⁵² NRECA Initial Comments at 45.

¹⁸⁵³ APPA Initial Comments at 32.

¹⁸⁵⁴ Michigan State Entities Initial Comments at 5–7; Six Cities Initial Comments at 2–3; Southern Initial Comments at 31; Vermont State Entities Initial Comments at 6–7.

¹⁸⁵⁵ Michigan State Entities Initial Comments at 5.

¹⁸⁵⁶ *Id.* at 6–7.

¹⁸⁵⁷ Six Cities Initial Comments at 2–3.

¹⁸⁵⁸ Vermont State Entities Initial Comments at 6–7.

¹⁸⁵⁹ Southern Initial Comments at 31.

¹⁸⁶⁰ City of New Orleans Council Initial Comments at 11; Entergy Initial Comments at 22; Louisiana Commission Initial Comments at 18; US Chamber of Commerce Initial Comments at 7–8.

Chamber of Commerce contends that the objective nature of such metrics should limit uncertainty otherwise present in projections spanning multiple decades and reduce the variability and error in benefit calculations.¹⁸⁶¹ Acadia Center and CLF and ACEG argue that an unbiased analysis of both benefits and costs is essential for ensuring just and reasonable rates and that the Commission should seek to ensure that a minimum set of benefits is applied consistently across RTO/ISO and non-RTO/ISO transmission planning regions.¹⁸⁶² ACORE agrees with US DOE that consistency in benefit quantification could facilitate improved interregional transmission planning.¹⁸⁶³

836. Other commenters state that the NOPR's proposed reforms will help improve transmission providers' existing benefit-cost analyses.¹⁸⁶⁴ GridLab states that the NOPR's approach balances regional flexibility with Federal standardization in benefit categories across transmission providers and more accountability by transmission providers in their benefit-cost analysis.¹⁸⁶⁵ PJM Market Monitor states that PJM's current benefit-cost analysis does not accurately measure the costs and benefits of transmission projects because it does not account for the fact that benefits are uncertain and sensitive to modeling assumptions or that costs may exceed estimates.¹⁸⁶⁶ Illinois Commission states that the use of too many metrics could lead to the evaluation of transmission projects based on the margins and inequitable cost allocation.¹⁸⁶⁷ Illinois Commission further states that some metrics may be most relevant for interregional and regional transmission projects identified in the Long-Term Regional Transmission Planning process and that the Commission can aid transmission planning regions in putting together a shorter list of these metrics.¹⁸⁶⁸

c. Commission Determination

837. We adopt the NOPR proposal, with modification, and require transmission providers in each transmission planning region to include in their OATTs a general description of

how they will measure each of the seven benefits included in the required set of benefits that we require them to measure and use in Long-Term Regional Transmission Planning. As discussed above, we clarify that transmission providers may use and measure additional benefits, beyond the seven required by this final order.¹⁸⁶⁹

838. We find that requiring such a description in transmission providers' OATTs for the seven required benefits is necessary to ensure that all stakeholders have transparency regarding the benefits that transmission providers use to identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. We further conclude that requiring inclusion of this information in the OATT will better ensure transmission providers measure and use the set of benefits required in the final order in Long-Term Regional Transmission Planning.

839. Some commenters express concerns regarding excessive quantification of benefits.¹⁸⁷⁰ But the approach adopted in this final order—of requiring transmission providers to measure and use a required set of benefits in Long-Term Regional Transmission Planning and requiring transmission providers to include in their OATTs a general description of the method they will use to measure each of those benefits—represents a reasonable balance between specificity and flexibility. As discussed above, we provide flexibility to transmission providers to specify the method for measuring each of the seven required benefits. However, because our requirement that transmission providers measure and use these benefits in Long-Term Regional Transmission Planning is necessary to address the identified deficiencies in existing regional transmission planning and cost allocation processes, we find that it is also necessary for transmission providers to include in their OATTs a general description of how they will measure each of these benefits. Such a requirement will ensure that transmission providers consider a

sufficiently broad range of benefits when determining whether to select a Long-Term Regional Transmission Facility as a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs.

840. In response to some commenters, such as MISO, that urge that requiring details on measurement of benefits to be incorporated into the OATT could impede development and use of new transmission metrics, we clarify that the description for each required benefit in the OATT must only be sufficient to enable stakeholders to understand the manner by which transmission providers will measure these benefits. We do not require further details on measurement of the benefits to be included in the OATT.

841. Large Public Power asks that the Commission clarify that any acceptable list of benefits detailed in compliance filings must emphasize load-serving entities' actual use of the proposed transmission facilities, which should be measured by anticipated power flows that occur across these facilities.¹⁸⁷¹ We decline to adopt Large Public Power's suggested clarification as we are not mandating any particular method for measuring the seven benefits included in the required set of benefits.

842. We decline certain commenters' requests to require that transmission providers justify why they omit any categories of benefits.¹⁸⁷² Such a requirement is unnecessary because of our modifications to the NOPR proposal, which now require transmission providers to measure and use the required set of benefits in Long-Term Regional Transmission Planning.

4. Evaluation of Transmission Benefits Over a Longer Time Horizon

a. NOPR Proposal

843. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the regional transmission facilities.¹⁸⁷³

844. The Commission proposed to require transmission providers to evaluate benefits over this time horizon in all stages of Long-Term Regional Transmission Planning, which includes evaluating regional transmission

¹⁸⁶¹ US Chamber of Commerce Initial Comments at 8.

¹⁸⁶² Acadia Center and CLF Initial Comments at 23; ACEG Initial Comments at 32.

¹⁸⁶³ ACORE Reply Comments at 3 (citing US DOE Initial Comments at 31).

¹⁸⁶⁴ GridLab Initial Comments at 25; PJM Market Monitor Initial Comments at 4–5; Southeast PIOs Initial Comments at 49–50.

¹⁸⁶⁵ GridLab Initial Comments at 25.

¹⁸⁶⁶ PJM Market Monitor Initial Comments at 4–5.

¹⁸⁶⁷ Illinois Commission Initial Comments at 13.

¹⁸⁶⁸ *Id.* at 14.

¹⁸⁶⁹ While we conclude that it is important for transmission providers to at minimum use and measure the required seven benefits, we agree with MISO that the flexibility to look for relevant benefits and apply them in long-term planning scenarios can be important in the process to identify long-term regional solutions that reflect region-specific needs and value-drivers. MISO Initial Comments at 9. We therefore afford flexibility to transmission planners in identifying and measuring benefits that go beyond the core set of seven required here.

¹⁸⁷⁰ See, e.g., Duke Initial Comments at 24.

¹⁸⁷¹ Large Public Power Initial Comments at 28.

¹⁸⁷² GridLab Initial Comments at 25; NYISO Initial Comments at 37–38; Vermont State Entities Initial Comments at 6–7.

¹⁸⁷³ NOPR, 179 FERC ¶ 61,028 at P 227.

facilities, selecting more efficient or cost-effective regional transmission facilities in the regional transmission plan for purposes of cost allocation, and allocating the costs of such regional transmission facilities in a manner that is at least roughly commensurate with estimated benefits. The Commission proposed that for consistency and a matching comparison of benefits and costs over time, to the extent that transmission providers estimate the costs of transmission facilities beyond the in-service date of the transmission facilities, that transmission providers should estimate those future costs over the same time horizon as the estimated benefit.¹⁸⁷⁴ The Commission proposed that approaches may exceed this minimum requirement, but transmission providers must demonstrate that their proposal is consistent with or superior to any final order in this proceeding.

b. Comments

i. Requirement for a Benefits Evaluation Time Horizon of a Minimum of 20 Years From the In-Service Date

845. Several commenters support the Commission's proposal to require that transmission providers in each transmission planning region evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities.¹⁸⁷⁵ NARUC, for example, states that transmission planning must strike a reasonable balance between considering benefits only through the end of the transmission planning horizon regardless of the transmission facility's in-service date and considering benefits over its full expected life, which NARUC states that the NOPR proposal achieves.¹⁸⁷⁶ Northwest and Intermountain state that they cautiously support the Commission's proposal to establish a minimum 20-year horizon for the calculation of benefits, noting that their concerns are mitigated by the NOPR proposal to allow flexibility within each transmission planning region to tailor cost allocation criteria to that region's needs.¹⁸⁷⁷ Similarly, Vermont State Entities and NESCOE

state that a rigid one-size-fits-all rule could be counterproductive and would not necessarily lead to just and reasonable transmission rates.¹⁸⁷⁸ NARUC states that, while it supports the NOPR proposal, transmission providers should be allowed independent entity variations to deviate above or below the 20-year horizon after gaining experience with Long-Term Regional Transmission Planning.¹⁸⁷⁹ NYISO contends that it already employs a 30-year study period in evaluating the benefits of transmission projects in its public policy transmission planning process.¹⁸⁸⁰

846. MISO supports the Commission's proposal, stating that a minimum period of 20 years is adequate to assess the benefits of regional transmission facilities.¹⁸⁸¹ MISO cautions, however, that the benefits determined over this time horizon represent the minimum benefits that a regional transmission facility provides and that the analysis should recognize that additional benefits would be realized over the life of the investment even if changing system conditions create uncertainty as to the precise value of those benefits.¹⁸⁸²

847. Other commenters suggest that the time horizon for the evaluation of benefits in Long-Term Regional Transmission Planning should align with the useful life of the transmission asset.¹⁸⁸³ Breakthrough Energy and CARE Coalition contend that the proper time horizon for evaluation of benefits in standard economics and public policy is the life of the transmission asset, noting that transmission assets can often last 40 years or longer.¹⁸⁸⁴ ACEG agrees, noting that, while it supports use of a 20-year minimum horizon to evaluate benefits, standard regulatory practice for a benefit-cost analysis is typically the life of the asset.¹⁸⁸⁵ Likewise, PIOs contend that, while they agree with the NOPR proposal, it would be preferable to align

the time horizon for evaluating benefits with the useful life of the transmission project.¹⁸⁸⁶ PIOs state that calculating the benefits and costs of a transmission project over a shorter timespan can understate the benefit-cost ratio because benefits tend to grow over time, while transmission revenue requirements will decline over time as the asset is depreciated.¹⁸⁸⁷

848. CTC Global states that while it supports the NOPR proposal, it argues that it would be more appropriate to align the timeline for evaluating benefits with the asset life, because while advanced conductors are almost always more expensive than legacy conductors initially, their costs are offset by efficiency and resilience benefits decades into the future.¹⁸⁸⁸ Indicated PJM TOs state that benefits "should be calculated on the same time horizon as the project that is being assessed to allow for the ability to properly compare projects."¹⁸⁸⁹

849. Given that transmission assets often have a useful life of at least 40 years, US DOE encourages the Commission to require transmission providers to evaluate costs and benefits over a minimum of 30 years after the in-service date of a transmission facility rather than the proposed 20 years. According to US DOE, doing so would better align with the useful life assumptions that generation developers make.¹⁸⁹⁰

850. Clean Energy Buyers and PG&E suggest that benefits should be evaluated over the same 20-year horizon as the proposed Long-Term Regional Transmission Planning transmission planning horizon.¹⁸⁹¹ Similarly, PPL states that, while it supports the proposed 20-year minimum duration to evaluate benefits in Long-Term Regional Transmission Planning, the Commission should require transmission providers to measure benefits from the study date rather than the proposed in-service date of the Long-Term Regional Transmission Facility. PPL contends that the NOPR proposal would introduce significant variability that will make it challenging to align the outcome with the long-term need and would incentivize transmission developers to delay or adjust the timing

¹⁸⁷⁸ NESCOE Initial Comments at 45; Vermont State Entities Initial Comments at 6.

¹⁸⁷⁹ NARUC Initial Comments at 39–40.

¹⁸⁸⁰ NYISO Initial Comments at 40.

¹⁸⁸¹ MISO Initial Comments at 52.

¹⁸⁸² *Id.*

¹⁸⁸³ ACEG Initial Comments at 24; Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40–41; Clean Energy Associations Initial Comments at 21; CTC Global Initial Comments at 16–17; ENGIE Initial Comments at 2; ENGIE Reply Comments at 2; Indicated PJM TOs Initial Comments at 17–18; Interwest Initial Comments at 14; Interwest Reply Comments at 6–7; Pine Gate Initial Comments at 35; PIOs Initial Comments at 40–41; US DOE Initial Comments at 33–34; WIRES Initial Comments at 7.

¹⁸⁸⁴ Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40–41.

¹⁸⁸⁵ ACEG Initial Comments at 24.

¹⁸⁸⁶ PIOs Initial Comments at 40 (citing PIOs Initial Comments Ex. A, ¶¶ 24–29).

¹⁸⁸⁷ *Id.* (citing PIOs Initial Comments Ex. A, ¶ 28).

¹⁸⁸⁸ CTC Global Initial Comments at 16–17.

¹⁸⁸⁹ Indicated PJM TOs Initial Comments at 18.

¹⁸⁹⁰ US DOE Initial Comments at 33–34.

¹⁸⁹¹ Clean Energy Buyers Initial Comments at 20; PG&E Initial Comments at 7.

¹⁸⁷⁴ *Id.* P 228.

¹⁸⁷⁵ ACEG Initial Comments at 24; California Commission Initial Comments at 36; Certain TDUs Reply Comments at 3; ITC Initial Comments at 22–23; NARUC Initial Comments at 26–27; NYISO Initial Comments at 40; OMS Initial Comments at 8–9; Pacific Northwest State Agencies Initial Comments at 16–19.

¹⁸⁷⁶ NARUC Initial Comments at 26.

¹⁸⁷⁷ Northwest and Intermountain Initial Comments at 8.

of transmission projects to maximize the demonstrated benefit.¹⁸⁹²

851. In contrast, GridLab contends that the 20-year Long-Term Regional Transmission Planning transmission planning horizon need not correspond with the time horizon over which transmission providers evaluate the benefits and costs of potential transmission investments. GridLab recommends that the Commission clarify the distinction between the requirement for a 20-year transmission planning horizon and for a 20-year period to evaluate benefits, while keeping both requirements.¹⁸⁹³

852. Many commenters assert that evaluating benefits over a 20-year time horizon is difficult or speculative.¹⁸⁹⁴ Ohio Consumers and Dominion argue that, since transmission providers would be required to plan for potential transmission needs in 20 years and evaluate benefits over a 20-year project life span, the requirement effectively amounts to a 40-year cost allocation process and will be particularly challenging.¹⁸⁹⁵ APS agrees, stating that calculating benefits over a potential 40 years may lead to benefit calculations that are overstated or yield unreasonable or unrealistic results.¹⁸⁹⁶

853. Some commenters request certain clarifications or modifications to address that uncertainty.¹⁸⁹⁷ For example, Exelon states that benefits should tie back to customer value and suggests that the Commission should give transmission providers flexibility to assign more weight to nearer-term benefits tied to specific savings that are more certain.¹⁸⁹⁸ SERTP Sponsors and Duke agree, and Duke requests that the Commission clarify that transmission providers are permitted to discount benefits based on increased uncertainty in later years for purposes of evaluating, selecting, and allocating the costs of Long-Term Regional Transmission Facilities.¹⁸⁹⁹

854. Several commenters oppose requiring a minimum 20-year horizon for evaluating benefits of Long-Term

Regional Transmission Facilities.¹⁹⁰⁰ For example, Idaho Commission argues that the NOPR proposal is founded on benefits that are not “generally accepted or regionally flexible” and may not be beneficial for regional transmission planning benefit evaluation.¹⁹⁰¹ Furthermore, Idaho Commission argues, it is difficult to accurately predict and quantify benefits over a 20-year period for purposes of cost allocation.¹⁹⁰²

855. Similarly, Dominion requests that the Commission decline to adopt the NOPR proposal or provide clarification that the Commission did not intend to propose that benefits would need to be evaluated over a potential 40-year period. Dominion states that it would be unreasonable for the Commission to require transmission providers to consider benefits over a 40-year period, because identifying benefits and beneficiaries that far into the future would involve too much speculation.

856. Pennsylvania Commission requests that the Commission revise the NOPR proposal to set a long-term horizon of no longer than 20 years for planning and benefit-cost analysis. Pennsylvania Commission argues that as the planning and benefit-cost analysis horizons lengthen, uncertainty in predictions of load growth, costs, and benefits will increase, potentially leading to uneconomic transmission projects.¹⁹⁰³ Pacific Northwest Utilities oppose the NOPR proposal because, they argue, beneficiaries and benefits cannot be identified or quantified with any reasonable certainty over a 20-year transmission planning horizon. Specifically, Pacific Northwest Utilities contend that there is no plausible reason to believe that such speculative benefits would be roughly commensurate with the costs that are allocated to identified beneficiaries.¹⁹⁰⁴

ii. Applicability of Benefits Evaluation Horizon to Long-Term Regional Transmission Planning Stages (Evaluation of Facilities, Selection, and Cost Allocation)

857. Pacific Northwest State Agencies supports the Commission’s proposal to require that transmission providers evaluate benefits over a consistent time horizon in all stages of Long-Term

Regional Transmission Planning, which includes evaluating regional transmission facilities, selecting more efficient or cost-effective regional transmission facilities in the regional transmission plan for purposes of cost allocation, and allocating the costs of such transmission facilities in a manner that is roughly commensurate with estimated benefits.¹⁹⁰⁵

858. Several commenters also support the Commission’s proposal that, to the extent that transmission providers estimate the costs of transmission facilities beyond the in-service date of the transmission facilities, they should estimate those future costs over the same time horizon as the estimated benefits.¹⁹⁰⁶ For instance, MISO states that costs and benefits for regional transmission investments should be evaluated using the same time horizon to ensure there is consistency in accounting for the effects of time in the calculations.¹⁹⁰⁷ MISO attests that since benefits are only realized once a transmission project or portfolio of projects is in service, transmission providers should assess the benefits over the period of time starting with the in-service date to align with costs.¹⁹⁰⁸ Pacific Northwest State Agencies and Certain TDUs agree.¹⁹⁰⁹

c. Commission Determination

859. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region, as part of Long-Term Regional Transmission Planning, to calculate the benefits of Long-Term Regional Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities, and we require that this minimum 20-year benefit horizon be used both for the evaluation and selection of Long-Term Regional Transmission Facilities.¹⁹¹⁰ However,

¹⁹⁰⁵ Pacific Northwest State Agencies Initial Comments at 18.

¹⁹⁰⁶ Certain TDUs Reply Comments at 3 (citing MISO Initial Comments at 53); MISO Initial Comments at 53; NARUC Initial Comments at 27; OMS Initial Comments at 8–9; Pacific Northwest State Agencies Initial Comments at 18.

¹⁹⁰⁷ MISO Initial Comments at 53.

¹⁹⁰⁸ *Id.*

¹⁹⁰⁹ Certain TDUs Reply Comments at 3 (citing MISO Initial Comments at 53); Pacific Northwest State Agencies Initial Comments at 18.

¹⁹¹⁰ In the NOPR, the Commission used the term “regional transmission facilities”; however, as this reform only concerns Long-Term Regional Transmission Planning, we clarify that the Commission’s intent was to refer only to Long-Term Regional Transmission Facilities. As discussed in the Development of Long-Term Scenarios section, transmission providers also use these benefits to help to inform their identification of Long-Term

¹⁸⁹² PPL Initial Comments at 15–17.

¹⁸⁹³ GridLab Initial Comments at 6–8.

¹⁸⁹⁴ APPA Initial Comments at 32; Dominion Initial Comments at 17; Louisiana Commission Initial Comments at 18; NRECA Initial Comments at 46; Ohio Consumers Initial Comments at 8; PJM Initial Comments at 97.

¹⁸⁹⁵ Ohio Consumers Initial Comments at 8.

¹⁸⁹⁶ APS Initial Comments at 8–9.

¹⁸⁹⁷ Duke Initial Comments at 23–24; Exelon Initial Comments at 16; SERTP Sponsors Initial Comments at 31.

¹⁸⁹⁸ Exelon Initial Comments at 16.

¹⁸⁹⁹ Duke Initial Comments at 23–24; SERTP Sponsors Initial Comments at 31.

¹⁹⁰⁰ Dominion Reply Comments at 4–5; Idaho Commission Initial Comments at 4; NARUC Initial Comments at 5–6; NESCOE Initial Comments at 44–45; Pacific Northwest Utilities Initial Comments at 6–7; Pennsylvania Commission Initial Comments at 4–5.

¹⁹⁰¹ Idaho Commission Initial Comments at 4.

¹⁹⁰² *Id.*

¹⁹⁰³ Pennsylvania Commission Initial Comments at 4–5.

¹⁹⁰⁴ Pacific Northwest Utilities Initial Comments at 7 (citing *ICC v. FERC I*, 576 F.3d 470).

we do not adopt the NOPR proposal to require a minimum 20-year horizon to calculate benefits for purposes of cost allocation. As described in the Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities section of this final order, requiring transmission providers to adopt this provision for purposes of cost allocation would unduly complicate development and review of Long-Term Regional Transmission Cost Allocation Methods, with little incremental gain. Lastly, for consistency and a matching comparison of costs over time, we adopt the NOPR proposal to require that, to the extent that transmission providers estimate the costs of Long-Term Regional Transmission Facilities beyond the in-service date of the transmission facilities, they must estimate those future costs over the same time horizon as the estimated benefits.

860. We find that calculating benefits both for the evaluation and selection of Long-Term Regional Transmission Facilities over a timeline that covers, at a minimum, 20 years starting from the estimated in-service date of the Long-Term Regional Transmission Facility, strikes an appropriate balance. This balance reasonably reflects the benefits that a Long-Term Regional Transmission Facility is likely to provide over its useful life, a time period that can exceed 40 years,¹⁹¹¹ while recognizing the inherent difficulties in attempting to predict system conditions too far into the future. As described in the Long-Term Regional Transmission Planning section of this final order, the uncertainty associated with forecasting future transmission needs over a long-term transmission planning horizon can be mitigated through the use of multiple Long-Term Scenarios and sensitivities.

861. Specifically, this final order requires transmission providers to develop multiple plausible and diverse Long-Term Scenarios, which will allow transmission providers to better understand how certain categories of factors will give rise to Long-Term Transmission Needs, and also requires transmission providers to update their assumptions periodically. Additionally,

Transmission Needs that manifest during the 20-year transmission planning horizon.

¹⁹¹¹ ACEG Initial Comments at 24; Breakthrough Energy Initial Comments at 23; CARE Coalition Initial Comments at 40–41; Clean Energy Associations Initial Comments at 21; CTC Global Initial Comments at 16–17; ENGIE Initial Comments at 2; ENGIE Reply Comments at 2; Indicated PJM TOs Initial Comments at 18; Interwest Initial Comments at 14; Interwest Reply Comments at 7; Pine Gate Initial Comments at 35; PIOs Initial Comments at 40–41; US DOE Initial Comments at 33–34; WIREs Initial Comments at 7.

transmission providers are permitted to assess the extent to which the projected change to Long-Term Transmission Needs due to factors in Factor Categories Four through Seven is likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios.¹⁹¹² Because of these reforms, we believe that transmission providers will be able to identify Long-Term Transmission Needs with a higher likelihood of occurrence, and, therefore, the benefits resulting from Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address these Long-Term Transmission Needs will similarly be more certain.

862. Moreover, as described in the Evaluation and Selection of Regional Transmission Facilities section of this final order, we provide transmission providers with considerable flexibility to develop an evaluation process and selection criteria that will provide them the opportunity to select Long-Term Regional Transmission Facilities in a way that maximizes benefits accounting for costs over time without overbuilding transmission facilities. In particular, transmission providers have the flexibility to evaluate Long-Term Regional Transmission Facilities and their measured benefits across the different Long-Term Scenarios and sensitivities in a manner that addresses the inherent uncertainty in Long-Term Regional Transmission Planning, for example through the use of a least-regrets or a weighted-benefits approach. Lastly, as is the case under the existing Order No. 1000 regional transmission planning processes, the final order does not require transmission providers to select any transmission facilities as part of Long-Term Regional Transmission Planning. Taken together, the aspects of the final order described above offer transmission providers meaningful tools to address uncertainty in Long-Term Regional Transmission Planning, including the calculation of benefits.

863. We disagree with NESCOE and Vermont State Entities, who argue that a requirement to calculate benefits over a minimum of 20 years from the estimated in-service date is overly rigid and may not lead to transmission rates that are just and reasonable. As discussed above, this requirement strikes a reasonable balance between the benefits that a Long-Term Regional Transmission Facility is likely to provide over its useful life, while recognizing the inherent difficulties in

¹⁹¹² *Supra* Long-Term Regional Transmission Planning, Long-Term Scenarios Requirements, Categories of Factors section.

attempting to forecast system conditions too far into the future. Further, allowing transmission providers to calculate benefits over a shorter period would more likely undervalue the total benefits that Long-Term Regional Transmission Facilities can provide and could therefore lead to relatively inefficient and less cost-effective transmission development, as Long-Term Regional Transmission Facilities that provide significant net benefits may not be selected to address Long-Term Transmission Needs. Lastly, and as stated above, we are not requiring transmission providers to use a minimum 20-year horizon to calculate benefits for purposes of cost allocation.

864. Similarly, we also disagree with commenters that suggest that the results of the benefits evaluation would not be accurate or dependable enough for transmission providers to use in making the decision to select Long-Term Regional Transmission Facilities.¹⁹¹³ We further note that transmission providers in multiple transmission planning regions already evaluate the benefits of transmission facilities over a 20-year time horizon as part of their regional transmission planning processes.¹⁹¹⁴ For example, NYISO states that it employs a 30-year study period in evaluating the benefits of transmission projects in its public policy transmission planning process.¹⁹¹⁵

865. Some commenters suggest that the Commission should provide additional flexibility to account for uncertainty in calculating benefits over a minimum 20-year time horizon, including that the Commission make clear that transmission providers may discount or weight the calculated benefits based on the relative certainty throughout the benefits horizon.¹⁹¹⁶ As

¹⁹¹³ APPA Initial Comments at 32; APS Initial Comments at 8–9; Dominion Initial Comments at 17; Idaho Commission Initial Comments at 4; Louisiana Commission Initial Comments at 18; NRECA Initial Comments at 46; Ohio Consumers Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 7; PJM Initial Comments at 97.

¹⁹¹⁴ MISO Initial Comments at 52; NYISO Initial Comments at 40; *see also* MISO, *L RTP Business Case*, Long Range Transmission Planning Workshop, at 7 (Jan. 21, 2022, revised Feb. 2, 2022), <https://cdn.misoenergy.org/20220121%20L RTP%20Workshop%20Item%2004%20Business%20Case%20Presentation619895.pdf>; CAISO, *20-Year Transmission Outlook* (Jan. 31, 2022), <http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf>; SPP Engineering, *2021 SPP Transmission Expansion Plan Report* (Jan. 11, 2021), <https://spp.org/documents/56611/2021%20step%20report.pdf>.

¹⁹¹⁵ NYISO Initial Comments at 40.

¹⁹¹⁶ Duke Initial Comments at 23–24; Exelon Initial Comments at 16; SERTP Sponsors Initial Comments at 31.

we described above, this final order affords transmission providers considerable flexibility in how to address uncertainty in Long-Term Regional Transmission Planning, including by allowing transmission providers to assess the extent to which the projected change to Long-Term Transmission Needs due to factors in factor Categories Four through Seven is likely to be realized in full, in part, or exceeded, for purposes of developing a plausible and diverse set of Long-Term Scenarios. Given these flexibilities, we find that while transmission providers may discount the benefits calculated for purposes of determining a present value of those benefits, they may not further discount those benefits to reflect uncertainty over the minimum 20-year time horizon for calculating benefits.

866. In response to Dominion's request for clarification that the Commission did not intend to propose that benefits would need to be evaluated over a potential 40-year period, we reiterate that transmission providers must calculate the benefits of Long-Term Regional Transmission Facilities over a minimum of 20 years from their estimated in-service date, even if the estimated in-service date is 20 years into the future. The failure to take such an approach could result in transmission providers' consideration of a Long-Term Regional Transmission Facility's cost but not the facility's corresponding benefits.

867. We also decline to modify the proposal, as requested by Pennsylvania Commission,¹⁹¹⁷ to require a benefits horizon of no longer than 20 years as a means of reducing speculation and uncertainty in calculating benefits of Long-Term Regional Transmission Facilities, as well as NARUC's request that the Commission permit transmission providers to deviate below the 20-year benefit evaluation horizon. As explained above, a minimum of 20 years strikes a reasonable balance for calculating the benefits of Long-Term Regional Transmission Facilities. In addition, as indicated by many commenters, calculating the benefits of a Long-Term Transmission Facility over a time horizon longer than 20 years is consistent with the long life of transmission facilities—which generally exceeds 20 years by a substantial margin—and also consistent with the fact that transmission facilities may provide significant benefits over their entire useful life. While we reiterate that transmission providers must calculate the benefits of Long-Term Regional

Transmission Facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities, to the extent that transmission providers would like to consider a longer time horizon for the evaluation of benefits, they may propose to do so on compliance.

868. In response to Pacific Northwest Utilities' argument that transmission providers will be unable to identify the beneficiaries of Long-Term Regional Transmission Facilities over a 20-year time horizon, and therefore that the costs of Long-Term Regional Transmission Facilities will not be allocated in a manner that is roughly commensurate with the benefits received,¹⁹¹⁸ we note that this final order modifies the NOPR proposal and transmission providers are not required to use a benefits time horizon of 20 years for purposes of cost allocation. We find this modification to the final order moots Pacific Northwest Utilities' argument.

869. We disagree with PPL's comments arguing that calculating benefits from the estimated in-service date of a Long-Term Regional Transmission Facility will present challenges to align the outcome with the actual needs in Long-Term Regional Transmission Planning or otherwise create perverse incentives for transmission developers to delay or adjust the timing of certain transmission projects to maximize benefits.¹⁹¹⁹ To the contrary, establishing a minimum benefits horizon of 20 years starting from the estimated in-service date of Long-Term Regional Transmission Facilities will allow for a comparable evaluation of benefits that identified Long-Term Regional Transmission Facilities may provide, even when such facilities may be placed in service at different times during the transmission planning horizon. We therefore decline PPL's request that the Commission modify the proposal to require that transmission providers measure benefits for a minimum of 20 years starting from the study date, rather than the estimated in-service date of the Long-Term Regional Transmission Facility.

870. In response to GridLab's request that the Commission clarify the distinction between the requirements for a minimum 20-year transmission planning horizon and a minimum 20-year benefits evaluation period,¹⁹²⁰ we reiterate the example provided in the

NOPR whereby, if the Long-Term Regional Transmission Planning process identifies a Long-Term Regional Transmission Facility that is estimated to be in service in year 10 of the 20-year Long-Term Regional Transmission Planning horizon, then the estimate of benefits for that same facility will commence at year 10 and cover an additional 20 years. Thus, the requirement to use a 20-year transmission planning horizon is separate and distinct from the requirement to calculate benefits of an identified Long-Term Regional Transmission Facility over a minimum of 20 years from its estimated in-service date.

5. Evaluation of the Benefits of Portfolios of Transmission Facilities

a. NOPR Proposal

871. In the NOPR, the Commission proposed to provide transmission providers in each transmission planning region with the flexibility to propose to use a portfolio approach in the evaluation of benefits of regional transmission facilities through their Long-Term Regional Transmission Planning. Rather than mandating its use, the Commission encouraged the use of this approach by transmission providers.¹⁹²¹ The Commission proposed to require transmission providers that propose to use a portfolio approach to include in their OATTs provisions describing how they would analyze the benefits of regional transmission facilities under such an approach and whether the portfolio approach would be used for Long-Term Regional Transmission Planning universally or would be used only in certain specified instances.¹⁹²²

b. Comments

i. General Interest in the Use of Portfolios

872. Most commenters who addressed the issue support the use of a portfolio approach to the evaluation of the benefits of regional transmission facilities in Long-Term Regional Transmission Planning, under which transmission providers would evaluate multiple transmission facilities in an aggregated, integrated fashion rather than doing so on a facility-by-facility basis.¹⁹²³ Exelon states that benefits

¹⁹²¹ NOPR, 179 FERC ¶ 61,028 at PP 233–234.

¹⁹²² *Id.* P 234.

¹⁹²³ See, e.g., Acadia Center and CLF Initial Comments at 10; ACEG Initial Comments at 49; ACORE Initial Comments at 2; AEP Initial Comments at 6, 27–28; Ameren Initial Comments at 19; Clean Energy Associations Initial Comments at 10; Eversource Initial Comments at 25; Exelon

¹⁹¹⁷ Pennsylvania Commission Initial Comments at 4–5.

¹⁹¹⁸ Pacific Northwest Utilities Initial Comments at 7 (citing *ICC v. FERC I*, 576 F.3d 470).

¹⁹¹⁹ PPL Initial Comments at 15–17.

¹⁹²⁰ GridLab Initial Comments at 6–8.

assessments for portfolios are likely to be more robust and less sensitive to changes in study assumptions than project-by-project analyses, tend to have widely distributed benefits, which can help garner stakeholder support, and may provide for administrative efficiencies in transmission planning.¹⁹²⁴ ACEG states that portfolio planning more accurately evaluates the benefits that new transmission provides to the system.¹⁹²⁵ Georgia Commission states that evaluating transmission facilities collectively, rather than on a facility-by-facility basis, may provide a better picture of the benefits to each state or transmission planning region and result in a more robust selection of transmission facilities.¹⁹²⁶

873. Renewable Northwest states that using portfolios in transmission planning is a best practice because it more completely captures systems benefits and leads to cost efficiencies.¹⁹²⁷ Renewable Northwest also comments that singularly focused planning processes often fail to identify the most cost-effective and efficient investments and instead have led to a bottom-up approach that has created a patchwork of transmission projects with high costs largely borne by ratepayers.¹⁹²⁸ EEI explains that the portfolio approach comprehensively addresses a number of transmission needs while ensuring a “no regrets” set of beneficial regional transmission projects.¹⁹²⁹ Eversource states that a portfolio approach can allow transmission providers to devise a set of transmission solutions that collectively create the most value compared to a piecemeal process.¹⁹³⁰

874. AEP states that the portfolio approach offers three advantages: (1) it enables transmission planning regions to identify transmission projects with synergistic benefits across transmission planning regions because regions will be able to recognize the efficiencies of a collection of transmission projects that provide greater overall value to the grid

together than they each provide on an individual basis; (2) there are administrative efficiencies; and (3) a portfolio approach best incorporates consideration of non-transmission alternatives and grid-enhancing technologies.¹⁹³¹

875. Numerous commenters point to the MISO Multi-Value Project process as an example of the successful use of portfolios.¹⁹³² Clean Energy Associations state that the Multi-Value Project process has resulted in lower interconnection costs for generators as compared to transmission upgrades planned in response to interconnection requests.¹⁹³³ US DOE suggests the Multi-Value Project process is an example of the use of portfolios to generate benefits that exceed costs.¹⁹³⁴ MISO states that it has worked with stakeholders to apply broad benefit metrics in the evaluation of Multi-Value Projects to identify portfolios of projects with benefits spread broadly throughout the region.¹⁹³⁵

876. Some commenters believe that the Commission should require the use of portfolios in the evaluation of benefits of regional transmission facilities.¹⁹³⁶ US DOE supports requiring transmission planners to evaluate the benefits of proposed transmission facilities as a portfolio, rather than as individual investments, to reduce the uncertainty of estimating system-level benefits, to simplify cost allocation, and to reduce administrative burden.¹⁹³⁷ US DOE states that if the portfolio approach is inappropriate in a particular circumstance, the impacted entities could petition the Commission, on a case-by-case basis, to describe their proposed alternative approach.¹⁹³⁸

877. New Jersey Commission states that the evidence from multiple studies of and experiences with long-term multi-driver and portfolio-based transmission planning proves that these approaches save ratepayers billions of

dollars and failure to use them is *per se* unjust and unreasonable.¹⁹³⁹ Cypress Creek argues that a portfolio approach is essential to optimize benefits and reduce the likelihood of a state or agency derailing a transmission project with proven regional benefits.¹⁹⁴⁰

878. PIOs state that the costs of a transmission project in a rural area that enhances access to renewable resources may exceed its benefits when evaluated alone, but, if evaluated with another project that relieves congestion, the two projects may support power flows that would not otherwise be possible.¹⁹⁴¹ PIOs further state that portfolio planning can reduce the risk that transmission projects are underutilized because they were built for a single resource that is no longer used or only a narrow set of users were considered.¹⁹⁴²

879. ITC argues that the Commission should mandate the use of a portfolio approach in RTO/ISOs to ensure that the most efficient, cost-effective, and broadly beneficial set of transmission projects are selected in each transmission planning cycle.¹⁹⁴³ ITC states that the use of a portfolio approach ensures that the greatest number of subregions within a transmission planning region receive benefits from each transmission planning cycle and provides significant efficiency gains because transmission providers can examine the whole portfolio to ensure that benefits exceed costs.¹⁹⁴⁴

880. Pattern Energy urges the Commission to require transmission providers to adopt portfolio approaches and explain why a portfolio approach was not (or could not be) identified in any Long-Term Regional Transmission Plan when an incremental transmission solution is proposed.¹⁹⁴⁵ Pattern Energy suggests that, if the Commission does not require portfolios, it should set a voltage threshold to identify portfolio solutions and require that transmission providers must explain why a portfolio approach was not taken when proposing incremental transmission facilities at voltage levels above 100 kV.¹⁹⁴⁶ Similarly, Shell states that if the Commission does not require a portfolio approach, it should require transmission

Initial Comments at 15–16; Joint Consumer Advocates Initial Comments at 11; Massachusetts Attorney General Initial Comments at 15–16; Pacific Northwest State Agencies Initial Comments at 7; PG&E Initial Comments at 8; PJM Reply Comments at 23; PIOs Initial Comments at 28; TANC Initial Comments at 16; US DOE Initial Comments at 34–35.

¹⁹²⁴ Exelon Initial Comments at 15–16, 18 (citing NOPR, 179 FERC ¶ 61,028 at P 233).

¹⁹²⁵ ACEG Initial Comments at 49.

¹⁹²⁶ Georgia Commission Initial Comments at 7.
¹⁹²⁷ Renewable Northwest Initial Comments at 9–10 (citing Brattle-Grid Strategies Oct. 2021 Report at 23).

¹⁹²⁸ *Id.* at 9.

¹⁹²⁹ EEI Initial Comments at 15.

¹⁹³⁰ Eversource Initial Comments at 25.

¹⁹³¹ AEP Initial Comments at 27–28.

¹⁹³² See, e.g., EEI Initial Comments at 15; Clean Energy Associations Initial Comments at 10; MISO Initial Comments at 14; US DOE Initial Comments at 34–35 (citing Brattle-Grid Strategies Oct. 2021 Report at 65–66).

¹⁹³³ Clean Energy Associations Initial Comments at 10.

¹⁹³⁴ US DOE Initial Comments at 35 (citing Brattle-Grid Strategies Oct. 2021 Report at 65–66).

¹⁹³⁵ MISO Initial Comments at 14.

¹⁹³⁶ Acadia Center and CLF Initial Comments at 4–5; ACEG Initial Comments at 31, 48–49; Cypress Creek Reply Comments at 8–9; ITC Initial

Comments at 6, 23–24; Pattern Energy Initial Comments at 15–17; Pine Gate Initial Comments at 38–39; PIOs Initial Comments at 28; SEIA Initial Comments at 20–21; US DOE Initial Comments at 34–35; WATT Initial Comments at 8–9.

¹⁹³⁷ US DOE Initial Comments at 34–35.

¹⁹³⁸ *Id.* at 35.

¹⁹³⁹ New Jersey Commission Initial Comments at 7.

¹⁹⁴⁰ Cypress Creek Reply Comments at 9.

¹⁹⁴¹ PIOs Initial Comments at 31–32.

¹⁹⁴² *Id.* at 36.

¹⁹⁴³ ITC Initial Comments at 6, 23–24.

¹⁹⁴⁴ *Id.* at 23.

¹⁹⁴⁵ Pattern Energy Initial Comments at 15–17.

¹⁹⁴⁶ *Id.* at 17.

providers to explain why portfolios are not being used.¹⁹⁴⁷

ii. Interest in Flexibility in the Use of Portfolios

881. Many other commenters assert that the Commission should only permit, not require, the use of portfolios in the evaluation of benefits.¹⁹⁴⁸ For example, Duke states that a facility-by-facility approach may be better suited if Long-Term Scenarios reveal the same or nearly identical constraints in discrete and isolated areas of the transmission grid where upgrades would be beneficial, whereas if Long-Term Scenarios reveal more disparate issues in different scenarios a portfolio approach may be better suited to gaining consensus and allowing for more even distribution of benefits.¹⁹⁴⁹ Duke asks the Commission to provide that, on compliance, a transmission provider may document processes for switching between or using both a facility-by-facility analysis and a portfolio approach.¹⁹⁵⁰

882. Dominion Energy states that some transmission providers may not have a portfolio of transmission projects to examine. NYISO asserts that transmission providers should not be required to mix and match components of different transmission developers' proposed transmission solutions to develop a portfolio to address a single transmission need.¹⁹⁵¹ APPA and TANC urge the Commission to allow regional flexibility to use a portfolio approach to evaluate benefits.¹⁹⁵²

883. PPL argues that a portfolio approach should not be mandated because one-size-fits-all portfolio-based planning may have downsides and may not be applicable in all circumstances or transmission planning regions.¹⁹⁵³ PPL further states that relying on portfolios could lead to complications in siting and cost allocation.¹⁹⁵⁴ Relatedly,

Michigan Commission argues that requiring portfolios could cause unnecessary delays for transmission projects that have strong stakeholder buy-in and incentivize including transmission projects less deserving of regional cost allocation purely to bolster assertions that all zones in multi-state RTOs/ISOs will benefit.¹⁹⁵⁵

884. CAISO states that portfolio planning should be optional, arguing that CAISO's sequential transmission planning approach achieves multi-benefit and holistic objectives without requiring a portfolio approach.¹⁹⁵⁶ CAISO explains that a project-by-project review does not mean examining only one transmission need at a time or failing to consider transmission projects that meet multiple needs or deliver multiple benefits.¹⁹⁵⁷

iii. Interest in Including the Portfolio Approach in a Transmission Provider's OATT

885. In response to the Commission's proposal that a transmission provider that proposes a portfolio approach must include in its OATT a description of when it would use the approach and how it would analyze benefits, some commenters agree that even if use of portfolios is flexible, the Commission should have such a requirement.¹⁹⁵⁸ Vermont State Entities suggest that if a transmission provider elects to use a portfolio approach, it must include in its OATT a description of how it would use such an approach and whether that approach would be used universally or only in certain specified instances.¹⁹⁵⁹

iv. Integrating Economic and Reliability Planning With Long-Term Regional Transmission Planning

886. PIOs state that portfolio planning is necessary and that the use of portfolios should incorporate long-term reliability and economic needs and benefits along with long-term Public Policy Requirements, because doing so allows transmission providers to select transmission projects with the higher benefit-to-cost ratios that resolve needs at least cost.¹⁹⁶⁰ PIOs state that by assessing all transmission needs at once and evaluating potential solutions, stakeholders will be able to find more efficient solutions that address multiple transmission needs that affect different

jurisdictions simultaneously.¹⁹⁶¹ PIOs ask that the final order allow transmission providers to continue to address unforeseen short-term local reliability needs but establish a rebuttable requirement that all long-term economic, public policy, and regional reliability needs and benefits will be assessed on a portfolio basis in Long-Term Regional Transmission Planning.¹⁹⁶²

887. SEPA states that the portfolio approach can be further enhanced by considering all categories of benefits: reliability, economic, public policy, and resilience.¹⁹⁶³ Likewise, SEIA states that the Commission should require portfolio-based planning that integrates all relevant factors, reliability, economic, and public policy, into Long-Term Regional Transmission Planning.¹⁹⁶⁴ Acadia Center and CLF discuss portfolio planning as integrating Long-Term Regional Transmission Planning with economic and reliability planning and state that the final order should require portfolio-based planning that assesses economic, reliability, and other needs at the same time.¹⁹⁶⁵

v. Concerns With the Portfolio Approach

888. A few commenters express apprehension about the portfolio approach, including concerns that the use of portfolios may mask bad individual transmission projects in a portfolio or result in good transmission projects not being approved because of difficulties in obtaining multiple state approvals that may be necessary for a portfolio.¹⁹⁶⁶ For example, Pennsylvania Commission states that a portfolio approach may cause siting concerns if a single transmission project in a portfolio is found by a state siting authority to be inconsistent with its state's public interest and siting regulations.¹⁹⁶⁷ Idaho Commission opposes requiring the use of a portfolio under any circumstances, stating that flexibility is necessary in transmission planning. It further states that a Commission requirement to use a portfolio approach under certain circumstances without specifying what

¹⁹⁴⁷ Shell Initial Comments at 16.

¹⁹⁴⁸ APPA Initial Comments at 32; Arizona Commission Initial Comments at 8; California Commission Initial Comments at 36–37; Dominion Initial Comments at 36; Duke Initial Comments at 25; Georgia Commission Initial Comments at 25; Michigan Commission Initial Comments at 8; MISO Initial Comments at 54; NARUC Initial Comments at 27–29; Nebraska Commission Initial Comments at 7–8; NESCOE Initial Comments at 45; NYISO Initial Comments at 9, 41–42; PPL Initial Comments at 16–17; SDG&E Initial Comments at 3; SPP Initial Comments at 10; TANC Initial Comments at 16; TAPS Initial Comments at 14; Vermont State Entities Initial Comments at 7; Xcel Initial Comments at 12.

¹⁹⁴⁹ Duke Initial Comments at 25–26.

¹⁹⁵⁰ *Id.* at 25.

¹⁹⁵¹ NYISO Initial Comments at 41.

¹⁹⁵² APPA Initial Comments at 32; TANC Initial Comments at 16.

¹⁹⁵³ PPL Initial Comments at 16–17.

¹⁹⁵⁴ *Id.* at 17.

¹⁹⁵⁵ Michigan Commission Initial Comments at 8.

¹⁹⁵⁶ CAISO Reply Comments at 22.

¹⁹⁵⁷ *Id.* at 21–22.

¹⁹⁵⁸ Clean Energy Associates Initial Comments at 14; NESCOE Initial Comments at 45; Vermont State Entities Initial Comments at 7.

¹⁹⁵⁹ Vermont State Entities Initial Comments at 7.

¹⁹⁶⁰ PIOs Initial Comments at 30–32.

¹⁹⁶¹ *Id.* at 35.

¹⁹⁶² PIOs Initial Comments at 32.

¹⁹⁶³ SEPA Initial Comments at 1.

¹⁹⁶⁴ SEIA Initial Comments at 20–21.

¹⁹⁶⁵ Acadia Center and CLF Initial Comments at 4–5.

¹⁹⁶⁶ CAISO Reply Comments at 24; Duke Initial Comments at 25–26; Idaho Commission Initial Comments at 4; Louisiana Commission Initial Comments at 26; NARUC Initial Comments at 28; Pennsylvania Commission Initial Comments at 10; PPL Initial Comments at 17.

¹⁹⁶⁷ Pennsylvania Commission Initial Comments at 10.

these circumstances are could result in unjust and unreasonable rates.¹⁹⁶⁸ Louisiana Commission also opposes any requirement to use a portfolio approach and disagrees with the NOPR's encouragement of such an approach.¹⁹⁶⁹

c. Commission Determination

889. We adopt the NOPR proposal to allow, but not require, transmission providers in each transmission planning region to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities. Further, we adopt with modification the NOPR proposal to require transmission providers that propose to use a portfolio approach when evaluating the benefits of Long-Term Regional Transmission Facilities to include provisions in their OATTs regarding their use of the portfolio approach. While we adopt the NOPR proposal to require transmission providers to include provisions in their OATTs regarding their use of a portfolio approach, we do not adopt the other proposed requirements. Specifically, we decline to adopt the NOPR proposal to require transmission providers to indicate whether a portfolio approach will be used universally or only in certain specified instances or to describe how they will analyze the benefits of regional transmission facilities under a portfolio approach. These requirements could impede transmission provider consideration and development of portfolio approaches. In response to Duke's request that the final order provide transmission providers with the flexibility to switch between or use both facility-by-facility and portfolio approaches,¹⁹⁷⁰ we clarify that transmission providers may use either or both facility-by-facility and portfolio approaches within the same Long-Term Regional Transmission Planning cycle.

890. We find that there are numerous advantages to a portfolio approach to evaluating benefits, including administrative efficiencies related to economies of scale and a more stable or even distribution of benefits that may result from a portfolio evaluation, which is likely to facilitate agreement on regional cost allocation. However, these advantages must be balanced against other considerations, and we therefore find that providing transmission providers in each transmission planning region with flexibility as to whether to use a portfolio approach is appropriate. Accordingly, we decline the request of

some commenters¹⁹⁷¹ to require transmission providers to use a portfolio approach.

6. Issues Related to Use of Benefits

a. NOPR Proposal

891. The Commission in the NOPR declined, consistent with Order No. 1000, to propose to prescribe any particular definition of "benefits" or "beneficiaries."¹⁹⁷²

b. Comments

892. Some commenters request specific definitions for the terms "benefits" or "beneficiaries" or offer guidance on definitions.¹⁹⁷³ NASUCA urges the Commission not to define benefits so broadly that every transmission project would qualify to be built, stating that overly broad benefit definitions reduce any rational relationship between cost allocation and identifiable beneficiaries.¹⁹⁷⁴

893. In contrast, other commenters agree with the Commission's proposal not to define "benefits" or "beneficiaries."¹⁹⁷⁵ For example, OMS and the Indiana Commission express support for the NOPR proposal to allow for flexibility in determining the definitions of benefits and beneficiaries for the purpose of selecting transmission facilities in Long-Term Regional Transmission Planning.¹⁹⁷⁶

894. Some commenters call for a state role in identifying benefits or metrics for use in Long-Term Regional Transmission Planning.¹⁹⁷⁷ California Commission states that the Commission should require transmission providers to demonstrate that they consulted with

the Relevant State Entities in their transmission planning region regarding benefits metrics.¹⁹⁷⁸ California Commission further states that the Commission should require transmission providers to indicate in their compliance filings whether their proposed benefits and metrics are supported by the Relevant State Entities, as well as to explain any points of disagreement.¹⁹⁷⁹ Likewise, New York Commission and NYSEERDA state that, especially in single-state RTOs/ISOs, the state should be afforded a central role in determining the benefits that transmission providers will consider and the metrics for quantifying them.¹⁹⁸⁰

895. North Carolina Commission and Staff state that, given the focus of the NOPR on transmission needs driven by changes in the generation mix and demand, which are areas of state jurisdiction, the Commission should require state agreement at every stage of the Long-Term Regional Transmission Planning process from identification of transmission needs, to the evaluation of the benefits of regional transmission facilities to meet those needs, to establishment of selection criteria, and finally to establishment of a cost allocation method.¹⁹⁸¹ Similarly, NESCOE explains that, while transmission providers have the technical expertise to identify, calculate, and explain the benefits that a given transmission facility may provide, states must be involved where state laws and policies are the project drivers.¹⁹⁸² As such, NESCOE requests that the Commission require that transmission providers either elevate and codify the states' role in all four phases of Long-Term Regional Transmission Planning or explain how and why, following consultation with the Relevant State Entities, the transmission provider developed a different approach.¹⁹⁸³ NESCOE asserts that this requirement would ensure that states, if they so elect, have a defined role in the evaluation phase of Long-Term Regional Transmission Planning.¹⁹⁸⁴

896. Virginia Commission Staff contends that the NOPR-identified benefits should be used only if affected

¹⁹⁷¹ Acadia Center and CLF Initial Comments at 4–5; ACEG Initial Comments at 31, 48–49; Cypress Creek Reply Comments at 8–9; ITC Initial Comments at 6, 23–24; Pattern Energy Initial Comments at 16–18; Pine Gate Initial Comments at 38–39; PIOs Initial Comments at 28; SEIA Initial Comments at 20–21; US DOE Initial Comments at 34–35; WATT Initial Comments at 8–9.

¹⁹⁷² NOPR, 179 FERC ¶ 61,028 at P 183 & n.324 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 624–625).

¹⁹⁷³ ELCON Initial Comments at 14–15; NASUCA Initial Comments at 10.

¹⁹⁷⁴ NASUCA Initial Comments at 10.

¹⁹⁷⁵ APPA Initial Comments at 31–33; Clean Energy Buyers Reply Comments at 9; Georgia Commission Initial Comments at 6–7; Indiana Commission Initial Comments at 6–7; Louisiana Commission Reply Comments at 9–10; Nebraska Commission Initial Comments at 7; TANC Initial Comments at 16; US Chamber of Commerce Initial Comments at 7–8.

¹⁹⁷⁶ Indiana Commission Initial Comments at 6–7; OMS Initial Comments at 13.

¹⁹⁷⁷ California Commission Initial Comments at 35; Massachusetts Attorney General Initial Comments at 14; Michigan Commission Initial Comments at 7–8; NESCOE Initial Comments at 41–43; North Carolina Commission and Staff Initial Comments at 6; PJM Market Monitor Initial Comments at 4.

¹⁹⁷⁸ California Commission Initial Comments at 35.

¹⁹⁷⁹ *Id.*

¹⁹⁸⁰ New York Commission and NYSEERDA Initial Comments at 8.

¹⁹⁸¹ North Carolina Commission and Staff Initial Comments at 6.

¹⁹⁸² NESCOE Initial Comments at 41–43.

¹⁹⁸³ *Id.* at 9–10, 41–43.

¹⁹⁸⁴ *Id.* at 41–43.

¹⁹⁶⁸ Idaho Commission Initial Comments at 4.

¹⁹⁶⁹ Louisiana Commission Initial Comments at 26.

¹⁹⁷⁰ Duke Initial Comments at 25–26.

states agree to their use.¹⁹⁸⁵ PJM Market Monitor agrees that it makes sense to attempt an evaluation of a broad set of benefits and beneficiaries through increased state involvement.¹⁹⁸⁶

897. Michigan Commission asserts that state regulators should be afforded substantial deference in identifying what benefit metrics and calculation methods should be used to justify long-term transmission plans, arguing that states with objections or concerns that an approved benefit metric is too speculative or otherwise inappropriate may find it more challenging to justify ratepayer investments and land condemnation in state siting proceedings.¹⁹⁸⁷ Massachusetts Attorney General states that the Commission should require that transmission providers establish an open and transparent process that provides states and other stakeholders with a meaningful opportunity to participate in the process of identifying the benefits to be used in Long-Term Regional Transmission Planning and determining how such benefits will be calculated.¹⁹⁸⁸ Several commenters state that decisions regarding benefit determination, metrics, and implementation of metrics should be made in coordination with all stakeholders.¹⁹⁸⁹ NRECA and Vermont State Entities assert that transmission providers should be required to demonstrate that all stakeholders are provided an opportunity to become fully aware of the analytic framework for incorporating benefits that will be used in Long-Term Regional Transmission Planning.¹⁹⁹⁰

898. PPL stresses the important role that states play in siting transmission facilities and the significance of benefits from transmission facilities in this process, cautioning that differences between states' and the Commission's delineation and evaluation of benefits will result in great uncertainty. PPL asserts that this uncertainty could lead to abandoned projects, costly litigation, and a largely underutilized planning tool, akin to transmission projects driven by public policy needs under Order No. 1000.¹⁹⁹¹

899. In contrast, ACORE notes that the benefits of transmission facilities are often spread out among states regardless of the state policies contributing to the need for such transmission facilities.¹⁹⁹²

900. SoCal Edison urges the Commission not to decouple policy projects from reliability and economic projects in transmission planning, so as to reduce barriers to regional coordination and ensure analysis of all potential benefits of a transmission project.¹⁹⁹³

901. Indiana Commission states that it supports the NOPR proposal as long as the final order provides for an equitable cost allocation method that allocates costs to the cost causer and beneficiaries of regional transmission development.¹⁹⁹⁴

c. Commission Determination

902. Consistent with the NOPR, we continue to decline to define "benefits" or "beneficiaries." We discuss above descriptions of the seven required benefits, and we further require transmission providers to propose a method to measure each of those benefits. These descriptions and requirements for these seven benefits will facilitate transparency regarding the use of benefits in Long-Term Regional Transmission Planning and represent an improvement in this respect over Order No. 1000, which lacked such descriptions.¹⁹⁹⁵ However, we do not believe that establishing a definition of "benefits" or "beneficiaries" would significantly improve upon these descriptions and we are concerned that any such definition could inadvertently exclude benefits and beneficiaries.

903. We acknowledge comments requesting greater clarity regarding states' roles in determining benefits in their transmission planning regions and regarding the benefits that will be used by transmission providers in Long-Term Regional Transmission Planning, including NRECA's and Vermont State Entities' assertions that transmission providers should be required to demonstrate that all stakeholders (including state entities and load-serving entities) are provided an opportunity to become fully aware of the analytic framework for incorporating benefits that will be used in Long-Term

Regional Transmission Planning.¹⁹⁹⁶ In response, we note this final order provides transmission providers with flexibility as to how they measure the seven required benefits, as well as flexibility to use additional benefits beyond the seven that we require. Consistent with other reforms in this final order incorporating an inclusive role for states in transmission planning, we encourage transmission providers to consult with states as they develop proposals to comply with the requirements of this final order and consider whether, and if so, how, to use additional benefits in Long-Term Regional Transmission Planning.¹⁹⁹⁷

E. Evaluation and Selection of Long-Term Regional Transmission Facilities

1. Requirement To Adopt an Evaluation Process and Selection Criteria

a. NOPR Proposal

904. In the NOPR, the Commission proposed to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs a transparent and not unduly discriminatory evaluation process and criteria to identify and evaluate transmission facilities (or portfolios of transmission facilities) for potential selection that address transmission needs driven by changes in the resource mix and demand.¹⁹⁹⁸ The Commission preliminarily found that the development and analysis of Long-Term Scenarios cannot remedy the deficiencies in the Commission's existing regional transmission planning requirements without the inclusion of such an evaluation process and selection criteria because, without them, transmission providers' Commission-jurisdictional rates may be unjust and unreasonable and unduly discriminatory and preferential.¹⁹⁹⁹

905. The Commission further proposed in the NOPR that, consistent with Order No. 1000, the developer of a transmission facility selected through Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand would be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility.

b. Comments

906. Many commenters support the Commission's proposal to require

¹⁹⁸⁵ Virginia Commission Staff Initial Comments at 5.

¹⁹⁸⁶ PJM Market Monitor Initial Comments at 4.

¹⁹⁸⁷ Michigan Commission Initial Comments at 7–8.

¹⁹⁸⁸ Massachusetts Attorney General Initial Comments at 14.

¹⁹⁸⁹ NYISO Initial Comments at 37; NRECA Initial Comments at 46; Vermont State Entities Initial Comments at 6.

¹⁹⁹⁰ NRECA Initial Comments at 46; Vermont State Entities Initial Comments at 6.

¹⁹⁹¹ PPL Initial Comments at 14–15.

¹⁹⁹² ACORE Initial Comments at 12; ACORE Reply Comments at 6.

¹⁹⁹³ SoCal Edison Initial Comments at 12–13.

¹⁹⁹⁴ Indiana Commission Initial Comments at 6–7.

¹⁹⁹⁵ As noted above, we do not require transmission providers to include additional benefits that they use for purposes of evaluation and selection of Long-Term Regional Transmission Facilities in their OATTs.

¹⁹⁹⁶ NRECA Initial Comments at 46; Vermont State Entities Initial Comments at 6.

¹⁹⁹⁷ See *supra* Other Benefits section.

¹⁹⁹⁸ See NOPR, 179 FERC ¶ 61,028 at PP 241–242.

¹⁹⁹⁹ *Id.* P 250.

transmission providers to include in their OATTs provisions providing criteria that they will use to identify and evaluate transmission facilities for potential selection to address transmission needs driven by changes in the resource mix and demand.²⁰⁰⁰ For example, Pacific Northwest State Agencies argue that this reform is critical to ensuring that Long-Term Regional Transmission Planning results in appropriate modeling and evaluation of Long-Term Regional Transmission Facilities.²⁰⁰¹ ACEG contends that transparent selection processes are key to reducing conflict (including costly litigation), developing legally sustainable long-term regional transmission plans, and maximizing benefits over time to consumers without over-building transmission facilities.²⁰⁰²

907. Other commenters oppose the Commission's proposal. Many of these commenters argue that Long-Term Regional Transmission Planning should be for informational purposes only and that the Commission should not require transmission providers to include selection criteria in their OATTs.²⁰⁰³ Alabama Commission contends that Long-Term Regional Transmission Planning should not involve selection or construction obligations unless the affected state regulators support such actions.²⁰⁰⁴ ELCON argues that selection should occur in "nearer-term planning (*i.e.*, 10–15 years)" when there is greater certainty that there is a specific transmission need.²⁰⁰⁵

²⁰⁰⁰ ACEG Initial Comments at 9; ACORE Initial Comments at 14; Amazon Initial Comments at 9; Ameren Initial Comments at 20; APPA Initial Comments at 33; CARE Coalition Initial Comments at 11–12; Clean Energy Buyers Initial Comments at 22; Exelon Initial Comments at 17; GridLab Initial Comments at 19; NRECA Initial Comments at 25; Ørsted Initial Comments at 5–6; Pacific Northwest State Agencies Initial Comments at 19; PPL Initial Comments at 18; Resale Iowa Initial Comments at 7–8.

²⁰⁰¹ Pacific Northwest State Agencies Initial Comments at 19.

²⁰⁰² ACEG Initial Comments at 9, 58.

²⁰⁰³ Alabama Commission Initial Comments at 3; ELCON Initial Comments at 10; Kansas Commission Initial Comments at 14; NRECA Initial Comments at 23–24; NRG Initial Comments at 6, 14; Ohio Consumers Initial Comments at 20; *see also* NARUC Initial Comments at 5 ("Long-Term Regional Transmission Planning [should] be used as a planning tool and not a construction requirement."); TANC Initial Comments at 10 (commenting that TANC "requests that the Commission clarify[] that the Commission is not proposing to require use of a 20-year planning horizon for . . . selecting Long-Term Regional Transmission Facilities").

²⁰⁰⁴ Alabama Commission Initial Comments at 3. Relatedly, Avangrid argues that the Commission should more clearly articulate how selection affects the actual construction of the transmission facility. Avangrid Initial Comments at 17.

²⁰⁰⁵ ELCON Initial Comments at 10–11.

908. Some commenters argue that it is unnecessary for the Commission to require that transmission providers include additional selection criteria in their OATTs. For example, Dominion contends that Order No. 1000 already requires transmission providers to include selection criteria in their OATTs, and that the final order should allow, but not require, them to add to those existing selection criteria.²⁰⁰⁶ Idaho Commission also believes that Order No. 1000's requirements are adequate and argues that the Commission has not demonstrated that there is a need to modify them.²⁰⁰⁷ Similarly, Idaho Power argues that selection criteria specific to Long-Term Regional Transmission Planning are unnecessary in light of existing processes to identify and evaluate transmission facilities in the NorthernGrid transmission planning region.²⁰⁰⁸ NYISO requests that the Commission confirm that the final order will not require changes to or the replacement of existing selection criteria.²⁰⁰⁹ Chemistry Council argues that the Commission should affirm that transmission providers must continue addressing nearer-term regional transmission needs, giving significant weight to transmission facilities that meet customer and end-user needs, ensure grid reliability and energy security, and prevent abandonment of needed resources.²⁰¹⁰

909. Clean Energy Buyers state that they support the NOPR proposal to grant eligibility to use the applicable cost allocation method to the developer of a Long-Term Regional Transmission Facility selected, subject to applicable development schedules. Clean Energy Buyers argue that this proposal could provide a more stable source of revenue and help resolve the "first-mover problem," which in turn could support additional transmission development.²⁰¹¹

910. Finally, SPP contends that allowing transmission providers to include selection criteria in business practice manuals rather than their OATTs would give them more flexibility if they need to adjust study approaches.²⁰¹²

²⁰⁰⁶ Dominion Initial Comments at 37 (citing NOPR, 179 FERC ¶ 61,028 at P 236).

²⁰⁰⁷ Idaho Commission Initial Comments at 4–5.

²⁰⁰⁸ Idaho Power Initial Comments at 8.

²⁰⁰⁹ NYISO Initial Comments at 43.

²⁰¹⁰ Chemistry Council Initial Comments at 6–7.

²⁰¹¹ Clean Energy Buyers Initial Comments at 21–22 (citing NOPR, 179 FERC ¶ 61,028 at P 247).

²⁰¹² SPP Initial Comments at 21–22.

c. Commission Determination

911. We adopt the NOPR proposal to require transmission providers in each transmission planning region to include in their OATTs an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs. We set forth requirements with respect to the evaluation process and selection criteria in the following sections.

912. We also adopt the NOPR proposal that, consistent with Order No. 1000, the transmission developer of a Long-Term Regional Transmission Facility that is selected, whether incumbent or nonincumbent, will be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility.

913. As explained above, transmission providers currently are not identifying or evaluating Long-Term Regional Transmission Facilities that might more efficiently or cost-effectively address Long-Term Transmission Needs and, therefore, do not have the opportunity to select such transmission facilities. We find that remedying these deficiencies in the Commission's existing regional transmission planning requirements requires the inclusion in transmission providers' OATTs of an evaluation process and selection criteria for Long-Term Regional Transmission Facilities, as outlined below, which, together with other aspects of this final order, will help to ensure that transmission providers' Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

914. We find that the inclusion in transmission providers' OATTs of an evaluation process and selection criteria for Long-Term Regional Transmission Facilities is essential to the reforms that we adopt in this final order. Without these essential components, Long-Term Regional Transmission Planning would merely inform the existing regional transmission planning processes rather than solving the deficiencies in the Commission's existing regional transmission planning requirements that we identify in this final order. The complete set of reforms that we adopt here are fundamental to resolving these deficiencies and to ensuring that transmission providers have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities to meet Long-Term Transmission Needs. Therefore, we disagree with commenters who suggest that an evaluation process or selection criteria are unnecessary or

inappropriate for the Long-Term Regional Transmission Planning²⁰¹³ reforms that we adopt in this final order.

915. We understand that transmission providers might propose to re-purpose existing evaluation processes or selection criteria (with or without modifications thereto) to use in Long-Term Regional Transmission Planning. In their compliance filings, transmission providers must propose the evaluation process and selection criteria that they will use in Long-Term Regional Transmission Planning, and they must demonstrate that they meet the final order requirements. In response to NYISO's request,²⁰¹⁴ however, we clarify that nothing in this final order requires transmission providers to modify or replace selection criteria used in their existing reliability and economic Order No. 1000 regional transmission planning processes.

916. As discussed below, to meet the requirements of this final order, transmission providers in each transmission planning region must establish a Long-Term Regional Transmission Planning evaluation process that: (1) identifies Long-Term Regional Transmission Facilities that address Long-Term Transmission Needs; (2) measures the benefits of the identified Long-Term Regional Transmission Facilities consistent with the final order requirements; and (3) designates a point in the evaluation process at which transmission providers will determine whether to select or not select identified Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.²⁰¹⁵ We recognize the inherent uncertainty involved in identifying Long-Term Transmission

Needs over the minimum transmission planning horizon adopted in this final order and in measuring the benefits that could be provided by Long-Term Regional Transmission Facilities. However, we continue to believe that there are selection criteria that transmission providers could adopt, following consultation with stakeholders and with Relevant State Entities in their transmission planning region's footprint, that minimize these risks while allowing for selection of Long-Term Regional Transmission Facilities that more efficiently or cost-effectively meet Long-Term Transmission Needs. We emphasize that we do not require transmission providers to select any particular Long-Term Regional Transmission Facilities but rather to adopt an evaluation process and selection criteria that meet the final order requirements. This evaluation process will ensure that Long-Term Regional Transmission Planning will provide transmission providers with a framework that allows for the selection of Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.²⁰¹⁶

917. We reiterate that, consistent with Order No. 1000,²⁰¹⁷ selection in the regional transmission plan does not entitle the transmission developer of a selected Long-Term Regional Transmission Facility to site or construct that transmission facility, nor does it obviate the need for the transmission developer to obtain other state, local, and/or Federal permits or authorizations. For this reason, we disagree with comments suggesting that the Commission proposed to do otherwise in the NOPR.²⁰¹⁸

918. Finally, we find that, consistent with the Commission's rule of reason,²⁰¹⁹ transmission providers' evaluation processes and selection criteria significantly affect rates, are reasonably susceptible to specification, and are not otherwise so generally understood as to render their recitation superfluous and therefore must be

included in their OATTs. As such, we reject SPP's request that we allow transmission providers to instead maintain evaluation processes and selection criteria in their business practice manuals.²⁰²⁰

2. Flexibility

a. NOPR Proposal

919. Subject to certain minimum requirements, the Commission proposed in the NOPR to provide transmission providers with the flexibility to propose the selection criteria that they, in consultation with their stakeholders, believe will ensure that more efficient or cost-effective regional transmission facilities to address the region's transmission needs driven by changes in the resource mix and demand ultimately are selected.²⁰²¹ The Commission stated that this proposed flexibility would help accommodate regional differences, such as differences in transmission needs, factors driving those needs, and market structures.²⁰²² The Commission stated that providing flexibility to propose evaluation processes and selection criteria would allow transmission providers, in consultation with their stakeholders, to determine criteria for assessing the efficiency or cost-effectiveness of various regional transmission facilities, whether by reference, for example, to a benefit-cost ratio or by aggregate net benefits.²⁰²³ The Commission stated that it further believed this proposed flexibility would allow transmission providers in each transmission planning region to develop selection criteria that could sufficiently balance individual state interests within each transmission planning region.²⁰²⁴

b. Comments

920. Many commenters support the Commission's proposal to provide transmission providers with the flexibility to propose an evaluation process and selection criteria that they, in consultation with their stakeholders, believe will ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities to address the transmission planning region's transmission needs driven by changes in the resource mix and demand ultimately are selected.²⁰²⁵

²⁰¹³ See, e.g., Alabama Commission Initial Comments at 3; Dominion Initial Comments at 37; ELCON Initial Comments at 10–11; Idaho Commission Initial Comments at 4–5; Idaho Power Initial Comments at 8; Kansas Commission Initial Comments at 14; NRECA Initial Comments at 23–24; NRG Initial Comments at 6, 14; TANC Initial Comments at 10; see also Ohio Consumers Initial Comments at 20 (arguing that a 20-year transmission planning horizon is inappropriate for constructing or allocating the costs of transmission facilities).

²⁰¹⁴ NYISO Initial Comments at 43. We reiterate that, as discussed above in the Participation in Long-Term Regional Transmission Planning section, transmission providers may propose to continue using some or all aspects of the existing regional transmission planning and cost allocation processes that they use to consider transmission needs driven by Public Policy Requirements, provided that transmission providers demonstrate that continued use of any such processes does not interfere with or otherwise undermine Long-Term Regional Transmission Planning as set forth in this final order.

²⁰¹⁵ See, e.g., NOPR, 179 FERC ¶ 61,028 at P 56 (setting forth requirements for Long-Term Regional Transmission Planning).

²⁰¹⁶ For these reasons, in addition to those discussed above, we disagree with ELCON that transmission providers should only select transmission facilities in "near-term planning (*i.e.*, 10–15 years)." ELCON Initial Comments at 10–11.

²⁰¹⁷ E.g., Order No. 1000–A, 139 FERC ¶ 61,132 at P 191.

²⁰¹⁸ See, e.g., Alabama Commission Initial Comments at 3; Dominion Reply Comments at 8 (citing PJOs Initial Comments at 28; NARUC Initial Comments at 5–6, 39); NARUC Initial Comments at 5, 39.

²⁰¹⁹ See *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210, at P 183 (2023) (citing *Hecate Energy Greene Cnty. 3 LLC v. FERC*, 72 F.4th 1307, 1314 (D.C. Cir. 2023); *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985)).

²⁰²⁰ SPP Initial Comments at 21–22.

²⁰²¹ NOPR, 179 FERC ¶ 61,028 at P 242.

²⁰²² *Id.* P 243.

²⁰²³ *Id.* P 243.

²⁰²⁴ *Id.* P 244.

²⁰²⁵ APPA Initial Comments at 33–34; Avangrid Initial Comments at 17; California Commission Initial Comments at 37; Chemistry Council Initial Comments at 6; Duke Initial Comments at 26; Eversource Initial Comments at 26; GridLab Initial Comments at 19; ISO–NE Initial Comments at 35;

921. For example, Nebraska Commission asserts that this flexibility will allow transmission providers to develop selection criteria that balance individual states' interests.²⁰²⁶ Eversource argues that flexibility will foster investments in cost-effective regional transmission facilities, accommodate differences in transmission needs between transmission planning regions, and encourage stakeholder engagement.²⁰²⁷ While NEPOOL supports flexibility as a general matter, it asserts that the Commission should articulate guiding principles for how selection decisions will be made and by whom, and guidelines regarding when transmission solutions should be selected to address long-term transmission needs.²⁰²⁸

922. By contrast, some commenters argue that the Commission should establish *pro forma* selection criteria.²⁰²⁹ Clean Energy Associations argues that doing so would enhance transparency, minimize differences across seams, and enable state regulators, consumers, and other market participants to evaluate transmission projects that result from Long-Term Regional Transmission Planning on an apples-to-apples basis.²⁰³⁰ Similarly, SEIA urges the Commission to establish a set of minimum requirements for selecting transmission facilities in Long-Term Regional Transmission Planning, arguing that transmission planning regions otherwise may fail to select transmission facilities that provide significant regional benefits.²⁰³¹ For its part, Clean Energy Buyers contends that adopting *pro forma* selection criteria would provide greater transparency and consistency across transmission planning regions, hopefully help to avoid disputes, and allow for consultation with states and other stakeholders.²⁰³²

923. Acadia Center and CLF argue that requiring a minimum set of selection criteria will provide critical information to transmission providers who rely on the Commission to make

clear what considerations they may weigh in Long-Term Regional Transmission Planning, facilitating more productive conversations at the regional level.²⁰³³

c. Commission Determination

924. Subject to the requirements described further below, we adopt the NOPR proposal to require transmission providers in each transmission planning region to propose, after consultation with Relevant State Entities and other stakeholders, evaluation processes, including selection criteria, that they believe will ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address the transmission planning region's Long-Term Transmission Needs. We believe that providing transmission providers with this flexibility will allow them to design evaluation processes and selection criteria that can accommodate regional differences.

925. We reject requests that, instead of providing transmission providers with flexibility, we set forth standard evaluation processes and selection criteria in this final order that transmission providers would be required to adopt.²⁰³⁴ While we recognize that there may be some benefits to doing so, we also find that transmission planning regions have different transmission needs and market structures that make designing a standard evaluation process and selection criteria difficult.

926. In response to NEPOOL,²⁰³⁵ we clarify that transmission providers make the selection decisions in Long-Term Regional Transmission Planning. Although we do not require transmission providers to select any particular Long-Term Regional Transmission Facility to address Long-Term Transmission Needs, as discussed below in the No Selection Requirement section, we do set forth minimum requirements with respect to the evaluation process and selection criteria, which will help to ensure that transmission providers select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address Long-Term Transmission Needs.

3. Minimum Requirements

a. NOPR Proposal

927. In the NOPR, the Commission proposed certain minimum requirements such that transmission providers' selection criteria must (1) be transparent and not unduly discriminatory; (2) aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation; and (3) seek to maximize benefits to consumers over time without over-building transmission facilities.²⁰³⁶ The Commission noted that, to comply with the Order Nos. 890 and 1000 transmission planning principles, the evaluation process must result in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected in the regional transmission plan for purposes of cost allocation to address transmission needs driven by changes in the resource mix and demand.²⁰³⁷ The Commission stated that the evaluation process and, specifically, the selection criteria, must seek to maximize benefits to consumers over time without over-building transmission facilities.²⁰³⁸

928. The Commission stated that providing flexibility to propose selection criteria would allow transmission providers, in consultation with their stakeholders, to determine criteria for assessing the efficiency or cost-effectiveness of various regional transmission facilities, whether by reference, for example, to a benefit-cost ratio or by aggregate net benefits.²⁰³⁹ The Commission also stated that transmission providers would have the flexibility to propose to use a portfolio approach in selecting regional transmission facilities that address transmission needs driven by changes in the resource mix and demand.²⁰⁴⁰ The Commission proposed to require transmission providers that propose such an approach to include in their OATTs provisions describing whether the selection criteria would apply to one proposed regional transmission facility or to a portfolio of regional transmission facilities, as well as whether the portfolio approach would be used for Long-Term Regional Transmission Planning universally to address transmission needs driven by changes in

MISO Initial Comments at 54; Nebraska Commission Initial Comments at 8; TAPS Initial Comments at 16; US Chamber of Commerce Initial Comments at 8.

²⁰²⁶ Nebraska Commission Initial Comments at 8 (citing NOPR, 179 FERC ¶ 61,028 at P 244).

²⁰²⁷ Eversource Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at PP 242–243).

²⁰²⁸ NEPOOL Initial Comments at 7–8.

²⁰²⁹ See, e.g., ACORE Reply Comments at 5–6 (citing Policy Integrity Initial Comments at 2–3); Policy Integrity Initial Comments at 2–3.

²⁰³⁰ Clean Energy Associations Initial Comments at 22–23.

²⁰³¹ SEIA Initial Comments at 5, 19.

²⁰³² Clean Energy Buyers Initial Comments at 22–23.

²⁰³³ Acadia Center and CLF Initial Comments at 10–11.

²⁰³⁴ Acadia Center and CLF Initial Comments at 10–11; Clean Energy Associations Initial Comments at 22–23; SEIA Initial Comments at 5, 19.

²⁰³⁵ NEPOOL Initial Comments at 8.

²⁰³⁶ NOPR, 179 FERC ¶ 61,028 at PP 241–242, 245.

²⁰³⁷ Id. P 242 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 328).

²⁰³⁸ Id.

²⁰³⁹ Id. P 243.

²⁰⁴⁰ Id. P 249.

the resource mix and demand or would be used only in certain specified instances.²⁰⁴¹

929. The Commission recognized the inherent uncertainty involved in predicting future transmission needs, including those driven by changes in the resource mix and demand, as well as the concerns that many commenters expressed in response to the ANOPR that imperfect information may lead to selecting transmission facilities that become stranded assets.²⁰⁴² The Commission also stated that there are selection criteria that transmission providers could adopt, following consultation with stakeholders and with Relevant State Entities in their transmission planning region's footprint, that could minimize these risks while allowing for investment in transmission facilities that more efficiently or cost-effectively meet transmission needs driven by changes in the resource mix and demand.²⁰⁴³ The Commission noted that under a "least-regrets" approach, for example, transmission providers in a transmission planning region would select a transmission facility (or portfolio of transmission facilities) that is net-beneficial in most or all Long-Term Scenarios, even if other transmission facilities have more net benefits or a higher benefit-cost ratio in a single Long-Term Scenario. The Commission stated that another approach is a "weighted-benefits approach," in accordance with which transmission providers in a transmission planning region would select a transmission facility (or portfolio of regional transmission facilities) based on its probability-weighted average benefits, where probabilities have been assigned to each Long-Term Scenario studied.²⁰⁴⁴

b. Comments

930. Commenters make a wide variety of arguments with respect to the minimum requirements that the Commission should impose with respect to evaluation processes and selection criteria. Many commenters support the Commission's proposal to require that selection criteria: (1) be transparent and not unduly discriminatory; (2) aim to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation to address

transmission needs driven by changes in the resource mix and demand; and (3) seek to maximize benefits to consumers over time without over-building transmission facilities.²⁰⁴⁵

931. Some commenters generally support the Commission's proposal with certain modifications. For example, Ameren argues that requiring selection criteria to maximize benefits to consumers over time without over-building transmission facilities is highly subjective, because such a requirement could refer to maximizing gross or net benefits and because certain interpretations could override the consideration of costs.²⁰⁴⁶ Vistra likewise argues that the directive to maximize benefits to consumers over time without over-building transmission facilities is unhelpfully vague and that maximizing benefits should not be understood to disregard costs.²⁰⁴⁷ WATT Coalition states that the Commission should require maximization of net benefits and cautions that it would be unjust and unreasonable to ignore benefits or costs in the assessment of options.²⁰⁴⁸

932. GridLab argues that selection criteria should seek to manage uncertainty and risk, stating that the Commission should clarify that the criteria must address not only the risk of over-building but also of under-building transmission.²⁰⁴⁹ In contrast, New York State Department argues that selection criteria should be designed to minimize the financial risk to ratepayers of over-building the transmission system.²⁰⁵⁰ NYISO requests clarification on the definition of over-building and argues that the final order should provide additional guidance on how transmission planning regions should address this risk. NYISO contends that the final order should treat the risk of over-building as an additional qualitative criterion that transmission planning regions should consider, as informed by open and transparent stakeholder review.²⁰⁵¹

933. EEI contends that it is appropriate for the Commission to

provide guidance by providing non-mandatory factors for transmission planning regions to consider.²⁰⁵² ELCON argues that transparency with respect to selection criteria requires that the criteria and their proper weighting must be clear and easily accessible to consumers through transmission providers' OASIS and OATT.²⁰⁵³

934. Commenters make several arguments with respect to the metrics that the Commission should allow or require transmission providers to use when evaluating whether to select Long-Term Regional Transmission Facilities. For example, some commenters argue that transmission providers should select transmission facilities by using metrics that seek to maximize net benefits instead of ones that rely on benefit-cost ratios.²⁰⁵⁴ ACEG argues that the Commission can require metrics that seek to maximize net benefits using the same authority it relied upon in promulgating Order No. 1000.²⁰⁵⁵

935. Breakthrough Energy states that, while metrics such as benefit-cost ratios are useful indicators, the efficient solution is the one that maximizes net benefits.²⁰⁵⁶ WATT Coalition contends that, in Australia, the transmission planner lists all transmission facility alternatives ranked by the net present value of the consumer benefits that the alternatives would provide, and selects the option that provides the most benefits in the absence of a compelling reason not to do so.²⁰⁵⁷

936. MISO argues that selection criteria should maximize long-term transmission value, defined as the difference between total benefits and total costs on a present value basis over a pre-determined transmission planning horizon.²⁰⁵⁸ MISO contends that using such a metric is important when benefit-cost ratios are high and transmission expansion is substantial, as many of the benefits provided by new transmission facilities are difficult to quantify in terms of dollars despite providing significant qualitative benefits.²⁰⁵⁹ Relatedly, CTC Global argues that selecting transmission facilities with the lowest capital costs is no longer a best

²⁰⁴¹ *Id.*

²⁰⁴² *Id.* P 251.

²⁰⁴³ *Id.*

²⁰⁴⁴ *Id.* (citing Brattle-Grid Strategies Oct. 2021 Report at 59–60).

²⁰⁴⁵ See ACEG Initial Comments at 58–59; ACORE Initial Comments at 14; Amazon Initial Comments at 9; APPA Initial Comments at 33–34; CARE Coalition Initial Comments at 11–12; NESCOE Initial Comments at 46; NRECA Initial Comments at 25; Ørsted Initial Comments at 5–6; Pacific Northwest State Agencies Initial Comments at 19; PPL Initial Comments at 17–18; TAPS Initial Comments at 16.

²⁰⁴⁶ Ameren Initial Comments at 20 (citing NOPR, 179 FERC ¶ 61,028 at P 243 n.390).

²⁰⁴⁷ Vistra Initial Comments at 17–18.

²⁰⁴⁸ WATT Coalition Initial Comments at 9.

²⁰⁴⁹ GridLab Initial Comments at 19.

²⁰⁵⁰ New York State Department Initial Comments at 4.

²⁰⁵¹ NYISO Initial Comments at 43.

²⁰⁵² EEI Initial Comments at 45–46.

²⁰⁵³ ELCON Initial Comments at 17.

²⁰⁵⁴ ACEG Initial Comments at 49–50;

Breakthrough Energy Initial Comments at 23; Clean Energy Associations Initial Comments at 22; DC and MD Offices of People's Counsel Initial Comments at 33; Evergreen Action Initial Comments at 4; ITC Initial Comments at 25; WATT Coalition Initial Comments at 9.

²⁰⁵⁵ See ACEG Initial Comments at 49–50 (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 58).

²⁰⁵⁶ Breakthrough Energy Initial Comments at 23.

²⁰⁵⁷ WATT Coalition Initial Comments at 9.

²⁰⁵⁸ MISO Initial Comments at 55–56.

²⁰⁵⁹ *Id.*

practice, in light of increased debate in many RTOs/ISOs about issues such as mandated resource mixes, compensation in capacity markets, transmission planning criteria and cost allocation, and carbon taxes.²⁰⁶⁰ CTC Global asserts that, if a transmission project is selected with least capital cost as a selection criterion, consumers will pay higher energy costs and higher total costs than what they would pay if the Commission were to require transmission providers to evaluate the NOPR's proposed benefits as well as cost.²⁰⁶¹

937. Commenters also offer a variety of perspectives regarding benefit-cost ratios. Clean Energy Associations recommend that, if the Commission continues to allow benefit-cost ratios, such ratios not exceed Order No. 1000's maximum allowable benefit-cost ratio of 1.25-to-1.00.²⁰⁶² ITC argues that, if the Commission allows transmission providers to use benefit-cost ratios, it should require the use of a 1.00-to-1.00 benefit-cost ratio for the evaluation of candidate portfolios.²⁰⁶³ Cypress Creek asserts that the Commission should retain the maximum permitted benefit-cost ratio of 1.25-to-1.00 and consider lowering that threshold to 1.00-to-1.00 because a transmission facility with a benefit-cost ratio of at least 1.00-to-1.00 is beneficial.²⁰⁶⁴

938. Pattern Energy argues that the existing maximum 1.25-to-1.00 allowable benefit-cost ratio is too high for purposes of Long-Term Regional Transmission Planning. Pattern Energy explains that scenarios and sensitivities typically are created to bookend what the future may look like, and those bookends are often weighted lower than a "business as usual" scenario. In this context, Pattern Energy argues that a lower benefit-to-cost ratio is necessary because the standard to approve transmission facilities is so high that transmission ratepayers are not receiving an appropriate opportunity to realize the value of new transmission infrastructure. Pattern Energy suggests that a more reasonable benefit-cost ratio would be 1.10-to-1.00 but notes that a higher benefit-to-cost ratio may be appropriate to evaluate a portfolio of

transmission facilities (e.g., 1.15–1.25).²⁰⁶⁵

939. By contrast, New York State Department asserts that transmission providers should not select a transmission facility unless benefits in the long term greatly exceed costs and that adopting a much higher benefit-cost ratio than the existing 1.25 standard may be required (e.g., 2.25-to-1.00).²⁰⁶⁶

940. Some commenters express support for least-regrets²⁰⁶⁷ or weighted-benefits approaches²⁰⁶⁸ to selecting transmission facilities in Long-Term Regional Transmission Planning. For example, National Grid argues that identifying least-regrets transmission facilities should be the goal of Long-Term Regional Transmission Planning.²⁰⁶⁹

941. Avangrid explains that "no regrets" or "low regrets" transmission facilities are those that likely will be needed under multiple scenarios and a broad range of assumptions.²⁰⁷⁰ PG&E agrees and argues that these transmission facilities are most likely to realize projected benefits.²⁰⁷¹ PG&E states that transmission facilities that provide more limited benefits or benefits under a limited number of scenarios may require additional study and should not be selected until there is more certainty that their benefits will be realized.²⁰⁷²

942. Exelon also advocates for a least-regrets approach, arguing that it minimizes risk and maximizes value for customers and transmission owners.²⁰⁷³ Eversource contends that a least-regrets approach is most likely to build the consensus among stakeholders that can support transmission facilities through planning, financing, siting, and cost

allocation.²⁰⁷⁴ NRECA argues that a least-regrets approach will help mitigate the risk that consumers will pay for unnecessary transmission facilities.²⁰⁷⁵

943. ACORE recommends the use of a weighted-benefits approach, which ACORE argues has been endorsed in recent expert reports on transmission planning.²⁰⁷⁶ Dominion sees promise in both least-regrets and weighted-benefits approaches but argues that requiring transmission providers to propose specific selection criteria may result in litigation, delay, and increased costs.²⁰⁷⁷

944. New England for Offshore Wind argues that the Commission should require transmission providers to give preference to transmission facilities that perform well under a range of scenarios.²⁰⁷⁸ A number of commenters caution, however, that the Commission should allow transmission providers to select transmission facilities even where they are not net-beneficial in every Long-Term Scenario.²⁰⁷⁹

945. A number of commenters recommend accounting for siting considerations in various ways in the selection of transmission facilities. For example, CARE Coalition recommends that the Commission require transmission providers to work with state authorities and other stakeholders to develop environmental- and energy justice-based siting criteria to guide transmission project selection and cost allocation.²⁰⁸⁰ CARE Coalition also states that the Commission should allow RTOs/ISOs to take a flexible approach to identifying siting-based criteria that consider local and regional impacts, local and regional energy justice impacts (including use of existing transmission corridors and investment flow to disadvantaged communities as defined by the President's Justice40 Initiative), integration with plans for energy storage, and integration with major infrastructure development plans (e.g., highways, rail corridors).²⁰⁸¹ CARE Coalition states that planners and stakeholders should consider the

²⁰⁶⁵ Pattern Energy Initial Comments at 14–15.

²⁰⁶⁶ New York State Department Initial Comments, *Montalvo Aff.* at 14–15.

²⁰⁶⁷ See Avangrid Initial Comments at 10–11; Eversource Initial Comments at 26–27; Exelon Initial Comments at 18; GridLab Initial Comments at 19–20; National Grid Initial Comments at 11–12; NRECA Initial Comments at 48; PG&E Initial Comments at 6.

²⁰⁶⁸ See ACORE Initial Comments at 14 (citing Brattle-Grid Strategies Oct. 2021 Report at 59–60; Derek Stenclik and Ryan Deyoe, *Multi-Value Transmission Planning for a Clean Energy Future: A Report of the Transmission Benefits Valuation Task Force*, Energy Systems Integration Group, 37 (June 2022), <https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf>) (Energy Systems Integration Group June 2022 Report)); Clean Energy Associations Initial Comments at 22 (citing NOPR, 179 FERC ¶ 61,028 at P 251).

²⁰⁶⁹ National Grid Initial Comments at 11–12 (citing National Grid ANOPR Initial Comments at 16).

²⁰⁷⁰ Avangrid Initial Comments at 10–11.

²⁰⁷¹ PG&E Initial Comments at 6.

²⁰⁷² *Id.*

²⁰⁷³ Exelon Initial Comments at 18.

²⁰⁷⁴ Eversource Initial Comments at 26–27.

²⁰⁷⁵ NRECA Initial Comments at 48.

²⁰⁷⁶ ACORE Initial Comments at 14 (citing Brattle-Grid Strategies Oct. 2021 Report at 59–60; Energy Systems Integration Group June 2022 Report at 37).

²⁰⁷⁷ See Dominion Initial Comments at 38.

²⁰⁷⁸ New England for Offshore Wind Initial Comments at 2; see also Clean Energy Associations Initial Comments at 22 (arguing for selecting transmission facilities that maximize net benefits across multiple scenarios).

²⁰⁷⁹ ACEG Initial Comments at 7, 30; ACORE Initial Comments at 14; Evergreen Action Initial Comments at 4; Pine Gate Initial Comments at 37–38.

²⁰⁸⁰ CARE Coalition Initial Comments at 7–8.

²⁰⁸¹ *Id.* at 10.

²⁰⁶⁰ CTC Global Initial Comments at 6–7 (citing *State Voluntary Agreements to Plan and Pay for Transmission Facilities*, 175 FERC ¶ 61,225 (2021) (Christie, Comm'r, concurring at PP 4–5)).

²⁰⁶¹ *Id.* at 9.

²⁰⁶² Clean Energy Associations Initial Comments at 22.

²⁰⁶³ ITC Initial Comments at 25–26.

²⁰⁶⁴ See Cypress Creek Reply Comments at 8 & n.14 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 646).

economic, environmental, and other impacts associated with the full expected useful lives of proposed transmission and associated facilities.²⁰⁸²

946. Similarly, ACEG recommends selection criteria that account for whether potential transmission facilities use existing rights-of-way, contribute to equitable energy service, alleviate environmental justice concerns, or impact employment and economic development.²⁰⁸³ Exelon also recommends giving preference to approaches that prioritize existing rights-of-way, given that they are more readily accomplished and have fewer environmental impacts than greenfield transmission projects.²⁰⁸⁴

947. Acadia Center and CLF urge the Commission to provide transmission providers clear guidance, by adopting minimum selection criteria in the final order, on their ability to consider factors such as environmental justice, mitigating environmental impacts, use of existing transmission facilities, and non-transmission alternatives, which have community and environmental benefits. Acadia Center and CLF contend that the consideration of these issues is consistent with NEPA, the FPA, and state law, and that, in the absence of such guidance, transmission providers may continue to exclude consideration of these issues given concerns regarding their authority and jurisdiction to do so.²⁰⁸⁵ Grand Rapids NAACP also argues that the Commission has the authority to require that transmission providers explicitly incorporate energy equity and justice concerns into selection criteria, and that the Commission should do so in a final order.²⁰⁸⁶ WE ACT states that equity considerations and other non-energy benefits (e.g., pollution reduction, health, jobs, and local economic development) should be among the benefits that transmission providers could use in selecting transmission facilities.²⁰⁸⁷ PIOs assert that the Commission should require transmission providers to consider equity impacts when determining which transmission facilities to select, including whether construction of such facilities will impact environmental justice communities and what the

cumulative impacts of the facilities will be.²⁰⁸⁸

948. DC and MD Offices of People's Counsel suggest that transmission providers should select transmission facilities that optimize the interconnection of portfolios of generation resources, including those that deliver benefits arising from grid decarbonization and the benefits set forth in the NOPR.²⁰⁸⁹ Eversource argues that the Commission should consider requiring transmission providers to address needs identified in high-impact, low-frequency event scenarios, such that selection criteria would accommodate worst-case scenarios like Winter Storm Uri.²⁰⁹⁰ Exelon urges that selection criteria be tied to well-established and defined needs, like reliability and market economics, such as reduced production costs, congestion, or capacity costs.²⁰⁹¹

949. Duke asserts that selection of a transmission facility in the absence of clear consensus from load-serving entities, states, and/or customers would be problematic and thwart the Commission's objectives, especially where certain transmission facilities will not be supported by state commissions in siting decisions or by consumer advocates in cost recovery proceedings.²⁰⁹² As such, Duke argues that the Commission should allow transmission providers to include a qualitative selection criterion of whether there is state and consumer support for a particular Long-Term Regional Transmission Facility or portfolio of facilities.²⁰⁹³ New York TOs state that New York Commission should retain its flexibility under NYISO's public policy transmission planning process such that, when the New York Commission identifies a transmission need driven by Public Policy Requirements, it can also require certain selection criteria in addition to those in NYISO's OATT.²⁰⁹⁴

950. NYISO contends that the final order should continue to allow transmission providers to use a range of

qualitative and quantitative criteria to rank and select transmission projects as the more efficient or cost-effective transmission facility.²⁰⁹⁵ ACEG encourages the Commission to provide guidance in the final order as to selection criteria that meet its requirements, arguing that doing so would facilitate efficient compliance proceedings.²⁰⁹⁶

951. Maine Public Advocate also argues that the Commission should require transmission providers to select non-transmission alternatives when they meet an identified transmission need at the same or lower cost.²⁰⁹⁷

952. TAPS asserts that the Commission should require transmission providers to explain how their selection criteria would account for the uncertainty involved in predicting future transmission needs and to report "Affordability Metrics" that disclose the impact that selection of a particular transmission facility would have on transmission rates.²⁰⁹⁸ TAPS argues that these "Affordability Metrics" would enhance the transparency of stakeholder processes in Long-Term Regional Transmission Planning and assist states in discussions about cost allocation and in considering whether to voluntarily fund a particular transmission facility or portfolio of transmission facilities.²⁰⁹⁹

953. ELCON states that, given the potential for massive transmission investment in the next 10 to 25 years, it is vitally important that consumers be protected from any unnecessary costs.²¹⁰⁰ As such, ELCON argues that selection criteria must incorporate metrics for reliability and economic efficiency, incorporate all potential drivers of transmission needs, and afford greater weight to those transmission facilities that produce benefits in more than one category.²¹⁰¹

²⁰⁹⁵ NYISO Initial Comments at 39–40.

²⁰⁹⁶ ACEG Initial Comments at 59.

²⁰⁹⁷ Maine Public Advocate Initial Comments at 1–2.

²⁰⁹⁸ TAPS Initial Comments at 16–17.

²⁰⁹⁹ *Id.* at 19–20 (citing Alliant Energy, et al., ANOPR Initial Comments at 14; Alliant Energy, et al., ANOPR Reply Comments at 2–3).

²¹⁰⁰ ELCON Initial Comments at 16 (citing Eric Larson et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Net Zero America, 108 (Oct. 29, 2021), <https://www.dropbox.com/s/ptp92f65lgds5n2/Princeton%20NZA%20FINAL%20REPORT%20%2829Oct2021%29.pdf?dl=0>).

²¹⁰¹ *Id.*

²⁰⁸² PIOs Reply Comments at 17 (citations omitted).

²⁰⁸⁹ DC and MD Offices of People's Counsel Initial Comments at 38–39.

²⁰⁹⁰ Eversource Initial Comments at 26–27 (citing FERC, North American Electric Reliability Corporation, Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas, and the South-Central United States* (Nov. 2021), <https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and>).

²⁰⁹¹ Exelon Initial Comments at 18.

²⁰⁹² Duke Initial Comments at 26–27.

²⁰⁹³ *Id.* at 4, 26–27.

²⁰⁹⁴ New York TOs Initial Comments at 9, 11–12, 15.

²⁰⁸² *Id.*

²⁰⁸³ ACEG Initial Comments at 59.

²⁰⁸⁴ Exelon Initial Comments at 18.

²⁰⁸⁵ Acadia Center and CLF Initial Comments at 11–12.

²⁰⁸⁶ Grand Rapids NAACP Initial Comments at 17–23 (citations omitted).

²⁰⁸⁷ WE ACT Initial Comments at 5.

c. Commission Determination

i. Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities

954. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to propose evaluation processes, including selection criteria, that are transparent and not unduly discriminatory. Consistent with Order No. 1000,²¹⁰² we adopt the NOPR proposal to establish a requirement that transmission providers' evaluation of transmission facilities must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected. As discussed further below, we modify the NOPR proposal to include a requirement that the determination of why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected must include the measured benefits for each alternative Long-Term Regional Transmission Facility (or portfolio of such Facilities) considered in the Long-Term Regional Transmission Planning process.

955. We also adopt the NOPR proposal, with modification, to require transmission providers to propose on compliance evaluation processes, including selection criteria, that aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address Long-Term Transmission Needs. We modify the NOPR proposal to provide additional clarity as to how transmission providers' evaluation processes must aim to ensure the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities to address Long-Term Transmission Needs by adopting several requirements. First, transmission providers in a transmission planning region must identify one or more Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that address the Long-Term Transmission Needs that the transmission providers have identified through Long-Term Regional Transmission Planning. As part of this identification, consistent with Order Nos. 890 and 1000,²¹⁰³ nonincumbent transmission developers must be able to propose transmission

facilities in Long-Term Regional Transmission Planning. Thus, we clarify that transmission providers in each transmission planning region must make clear in their OATTs the point in the Long-Term Regional Transmission Planning evaluation process at which they will accept Long-Term Regional Transmission Facility proposals from stakeholders, including nonincumbent transmission developers. Second, transmission providers' evaluation processes must estimate the costs and measure the benefits of the Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that are identified or proposed for potential selection, in addition to evaluating the identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities) using any qualitative or other quantitative selection criteria that the transmission providers in a transmission planning region propose to apply. Third, transmission providers must designate a point in the evaluation process at which transmission providers will determine whether to select or not select identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities).²¹⁰⁴ This point must be no later than three years following the beginning of the Long-Term Regional Transmission Planning cycle.²¹⁰⁵ Finally, the evaluation process must culminate in determinations that are sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) was selected or not selected. We reiterate, however, that, as discussed further below in the No Selection Requirement section, this final order does not require transmission providers to select any particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) to address Long-Term Transmission Needs.

956. As discussed earlier, this final order requires transmission providers to develop and use at least three Long-Term Scenarios, and one sensitivity analysis applied to each Long-Term Scenario, when conducting Long-Term

Regional Transmission Planning. Each Long-Term Scenario or sensitivity analysis may suggest that different Long-Term Transmission Needs exist, that different Long-Term Regional Transmission Facilities would resolve those needs, or that such Long-Term Regional Transmission Facilities would provide different benefits for transmission customers. We clarify that, in the context of Long-Term Regional Transmission Planning, Order No. 890's requirements that transmission providers conduct coordinated, open, and transparent transmission planning on the regional level²¹⁰⁶ requires that transmission providers make transparent the methods that they used to analyze each individual Long-Term Scenario and the sensitivity or sensitivities applied to each scenario to determine the Long-Term Transmission Needs that exist in the transmission planning region, the Long-Term Regional Transmission Facilities that would resolve those needs, and the benefits of those Long-Term Regional Transmission Facilities for purposes of selection.²¹⁰⁷

957. Consistent with the Order No. 1000 regional transmission planning requirements,²¹⁰⁸ the Long-Term Regional Transmission Planning process must result in a regional transmission plan that identifies the Long-Term Regional Transmission Facilities that more efficiently or cost-effectively meet the transmission planning region's Long-Term Transmission Needs. To effectuate this requirement, we clarify that transmission providers have an affirmative obligation to identify Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs, regardless of whether any stakeholder proposes potential Long-Term Regional Transmission Facilities for consideration in Long-Term Regional Transmission Planning. In this section, we enumerate specific requirements for how transmission providers conduct their Long-Term Regional Transmission Planning with the aim to ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities

²¹⁰⁴ As described further below in the Voluntary Funding Opportunities section, transmission providers must also provide Relevant State Entities with the opportunity to fund the cost of, or part of the cost of, the Long-Term Regional Transmission Facility (or portfolio of such Facilities) to ensure that it meets the transmission providers' selection criteria.

²¹⁰⁵ We note, however, consistent with the discussion above in the Frequency of Long-Term Scenario Revisions section, that transmission providers may evaluate and select additional Long-Term Regional Transmission Facilities during the period of the Long-Term Regional Transmission Planning cycle after this point and before the commencement of the next such cycle.

²¹⁰⁶ Order No. 890, 118 FERC ¶ 61,119 at P 435.

²¹⁰⁷ For example, transmission providers might weigh specific Long-Term Scenarios and sensitivities based on the probability that the analyses reflect future system conditions (which the Commission referred to in the NOPR as a "weighted-benefits approach"). NOPR, 179 FERC ¶ 61,028 at P 251 (citing Brattle-Grid Strategies Oct. 2021 Report at 59–60).

²¹⁰⁸ Order No. 1000, 136 FERC ¶ 61,051 at PP 55, 146–148; see *Louisville Gas & Elec. Co.*, 144 FERC ¶ 61,054, at PP 61–62 (2013), *on reh'g sub nom., Duke Energy Carolinas LLC*, 147 FERC ¶ 61,241, at PP 82–83 (2014).

²¹⁰² Order No. 1000, 136 FERC ¶ 61,051 at P 328.

²¹⁰³ See *id.* P 315 (citing Order No. 890, 118 FERC ¶ 61,119 at P 494; Order No. 890–A, 121 FERC ¶ 61,297 at PP 215–216).

are selected. By clearly enumerating their evaluation processes and selection criteria in their OATTs, transmission providers will provide significant transparency to stakeholders to understand how Long-Term Transmission Needs will be addressed, whether there are more efficient or cost-effective Long-Term Regional Transmission Facilities that may meet those needs, and their benefits.

958. Provided that transmission providers' evaluation processes and selection criteria comply with the requirements that we adopt here, we provide transmission providers with flexibility to determine how they will evaluate whether Long-Term Regional Transmission Facilities more efficiently or cost-effectively address Long-Term Transmission Needs, including by using benefit-cost ratios, assessing their net benefits and selecting the Long-Term Regional Transmission Facilities that maximize those benefits, and/or using some other method.²¹⁰⁹ Consistent with Order No. 1000 regional cost allocation principle (3), and as further discussed below in the Regional Transmission Cost Allocation section, transmission providers may not impose as a selection criterion a minimum benefit-cost ratio that is higher than 1.25-to-1.00.²¹¹⁰ We decline to reduce or increase the maximum benefit-cost ratio that transmission providers may use as a selection criterion in Long-Term Regional Transmission Planning. As the Commission found in Order No. 1000,²¹¹¹ requiring that a benefit-cost ratio, if adopted, not exceed 1.25-to-1.00 ensures that the ratio is not so high as to exclude Long-Term Regional Transmission Facilities with significant positive net benefits from selection.

959. We decline to require transmission providers to account for siting considerations in their evaluation process and selection criteria.²¹¹² We acknowledge that siting considerations (e.g., use of existing rights-of-way) may

affect the costs, timeline, or feasibility of developing a Long-Term Regional Transmission Facility. While such siting considerations may inform the evaluation process and selection criteria, we do not require transmission providers to account for such considerations in this final order. We note, however, that, as discussed below in the Role of Relevant State Entities section, this final order requires that transmission providers consult with and seek the support of Relevant State Entities²¹¹³ regarding the evaluation process and selection criteria that transmission providers propose to use to evaluate Long-Term Regional Transmission Facilities for selection.

960. We also do not require transmission providers to include environmental justice or equity considerations in their evaluation process or selection criteria. While several commenters recommend that we impose such requirements,²¹¹⁴ none provides any approach for how these concerns would be incorporated into transmission providers' evaluation process and selection criteria on a generic basis. We acknowledge that the selection of Long-Term Regional Transmission Facilities represents a substantial step in the development of new electric transmission infrastructure, which may impact environmental justice communities or raise equity concerns. We further recognize that such environmental justice or equity considerations may affect the costs, timeline, or feasibility of developing a Long-Term Regional Transmission Facility, particularly in regions where legal frameworks provide for consideration of environmental justice and equity. Nothing in this final order precludes transmission providers from proposing on compliance to include environmental justice considerations within their evaluation process and selection criteria.

961. NYISO requests that the Commission clarify that transmission providers may continue to use qualitative and quantitative measures in the Long-Term Regional Transmission Planning process.²¹¹⁵ We clarify that nothing in this final order prohibits transmission providers from proposing to use qualitative factors in their evaluation processes and/or selection criteria. Accordingly, transmission

providers may propose to use qualitative factors in their evaluation processes and/or qualitative selection criteria, provided that they demonstrate on compliance that their proposals comply with the evaluation process and selection criteria requirements of this final order.

962. In response to Duke's request to allow transmission providers to include a selection criterion that is a qualitative evaluation of whether there is state and consumer support for a particular Long-Term Regional Transmission Facility or portfolio of such Facilities,²¹¹⁶ we find that transmission providers may not include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities. Rather than address this issue via selection criteria regarding a *transmission provider's* anticipation of such an entity's response, we conclude that the requirement discussed below to consult with and seek support from Relevant State Entities regarding the evaluation process and selection criteria is a more appropriate mechanism to account for the Relevant State Entity's views. We also note that beyond this consultative process, state public utility commissions and consumer advocates have numerous opportunities to express their views on transmission development, including through state- and Commission-jurisdictional proceedings. Further, allowing such features in evaluation processes or selection criteria could amount to a requirement that transmission providers obtain the consent of Relevant State Entities, which, as discussed below in the Role of Relevant State Entities section, we do not believe is necessary or appropriate to resolve the deficiencies identified in this final order.²¹¹⁷

963. In response to New York TOs,²¹¹⁸ we decline to require that transmission providers include selection criteria requested by state public utility commissions. As discussed further below in the Role of Relevant State Entities section, transmission providers must propose on compliance an evaluation process and selection criteria that comply with the

²¹⁰⁹ Nothing in this final order requires the use of any particular approach, and we clarify that transmission providers may use more than one approach complementarily. *Compare, e.g.,* MISO Initial Comments at 54–56 (explaining MISO's approach to selecting transmission facilities with the goal of maximizing "long-term transmission value"), *with* MISO, FERC Electric Tariff, MISO OATT, attach. FF, Transmission Expansion Planning Protocol (90.0.0), sections II.B.1.c, II.C.2.b (setting forth as a minimum selection criterion a benefit-cost ratio of 1.25 or 1.00 for Market Efficiency Projects and Multi-Value Projects, respectively).

²¹¹⁰ NOPR, 179 FERC ¶ 61,028 at P 243 n.390; Order No. 1000, 136 FERC ¶ 61,051 at P 646.

²¹¹¹ Order No. 1000, 136 FERC ¶ 61,051 at P 648.

²¹¹² CARE Coalition Initial Comments at 7–8; *see also* ACEG Initial Comments at 59; Exelon Initial Comments at 18.

²¹¹³ Many Relevant State Entities exercise their state's authority over the siting of transmission facilities.

²¹¹⁴ *See, e.g.,* Acadia Center and CLF Initial Comments at 11–12; Grand Rapids NAACP Initial Comments at 17–23 (citations omitted); PIOs Reply Comments at 17 (citations omitted).

²¹¹⁵ NYISO Initial Comments at 39–40.

²¹¹⁶ Duke Initial Comments at 4, 26–27.

²¹¹⁷ *See New York v. FERC*, 535 U.S. at 26–28 (upholding Commission's decision not to assert jurisdiction over bundled retail transmission).

²¹¹⁸ New York TOs Initial Comments at 9, 11–12, 15.

requirements of this final order after consulting with and seeking the support of Relevant State Entities. To the extent that a transmission provider believes that a selection criterion proposed by a Relevant State Entity would comply with the final order requirements, they may propose to include that criterion in their compliance filings, and the Commission will determine if it complies with these requirements.

ii. Maximize Benefits

964. We adopt the NOPR proposal, with modification, to require that transmission providers in each transmission planning region propose evaluation processes, including selection criteria, that seek to maximize benefits accounting for costs over time without over-building transmission facilities. In the NOPR, the Commission proposed that the evaluation processes and selection criteria seek to maximize benefits to consumers over time without over-building transmission facilities. However, we believe that it is appropriate to modify that proposal for clarity. We modify the requirement to require that transmission providers' evaluation processes and selection criteria seek to maximize benefits *accounting for costs*. Some commenters have interpreted the NOPR as proposing to allow transmission providers to disregard costs and simply maximize benefits.²¹¹⁹ We clarify that was not the Commission's intent, and we modify the NOPR proposal in this final order to make that clear. Further, we note that while we omit reference "to consumers" in the requirement for brevity, we do not view this change as substantive. As discussed above, this requirement, together with other aspects of this final order, helps to ensure transmission providers identify, evaluate, and select Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs in order to ensure just and reasonable Commission-jurisdictional rates, which ultimately benefits ratepayers.

965. As discussed in the Requirement for Transmission Providers to Use a Set of Seven Required Benefits section, transmission providers conducting Long-Term Regional Transmission Planning must use and measure a set of benefits to evaluate Long-Term Regional Transmission Facilities. In setting forth an evaluation process and selection criteria, we clarify, consistent with the

directive to seek to maximize benefits accounting for costs over time without over-building transmission facilities, that transmission providers may not disregard benefits that we require them to use and measure when implementing their approved evaluation process and selection criteria.²¹²⁰ We further clarify that transmission providers may not disregard benefits even where those benefits are only measured in certain transmission system conditions, such as may be the case with Benefit 6, Mitigation of Extreme Weather Events and Unexpected System Conditions, and therefore are captured only under certain Long-Term Scenarios or sensitivities thereto. While transmission providers may not disregard such benefits, transmission providers' evaluation processes and selection criteria may account for the fact that certain benefits are only measured under certain conditions by, for example, weighting how likely certain conditions expressed in specific Long-Term Scenarios or sensitivities are to occur.

966. As discussed further below, transmission providers have the discretion to select or not select any Long-Term Regional Transmission Facility that they identify through Long-Term Regional Transmission Planning, even a facility that otherwise meets the selection criteria. However, as noted above, the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular Long-Term Regional Transmission Facility was selected or not selected to address Long-Term Transmission Needs. We clarify that this determination must include the estimated costs and measured benefits of each alternative Long-Term Regional Transmission Facility (or portfolio of such Facilities) evaluated by the transmission providers, whether or not the Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected.²¹²¹

967. We acknowledge commenters' concerns that there is inherent uncertainty in Long-Term Regional Transmission Planning.²¹²² This final order adopts provisions that allow for significant flexibility for transmission providers to address that uncertainty. As stated above in the Participation in

Long-Term Regional Transmission Planning section, we require transmission providers to develop and use Long-Term Scenarios, which are a critical tool for managing uncertainty and facilitating regional transmission planning that account for a range of potential futures, as well as an assessment of the likelihood of each scenario manifesting, when identifying, evaluating, and selecting Long-Term Regional Transmission Facilities. Further, transmission providers could adopt evaluation processes and selection criteria that would allow transmission providers to make selection decisions while minimizing the future risk of developing a previously selected Long-Term Regional Transmission Facility that is not the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. For example, transmission providers might develop a least-regrets approach under which they would select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation if those Long-Term Regional Transmission Facilities are net beneficial in more than one Long-Term Scenario and sensitivity analyses even if other transmission facilities have a higher benefit-cost ratio or provide more net benefits in a single Long-Term Scenario or particular sensitivity. Transmission providers might also adopt a weighted-benefits approach under which they would select a Long-Term Regional Transmission Facility based on its probability-weighted average benefits, where probabilities have been assigned to each Long-Term Scenario or sensitivity thereof that is studied. Under either approach, to maximize benefits accounting for costs over time without over-building transmission facilities, transmission providers must consider not only the risk that changing conditions might produce fewer benefits than originally anticipated, but also that they might produce *more* benefits than originally anticipated. Finally, as discussed below in the Reevaluation section, we require transmission providers to reevaluate certain selected Long-Term Regional Transmission Facilities to determine whether they continue to meet the transmission providers' selection criteria.

968. While we acknowledge commenters' wide support for least-regrets and weighted-benefits approaches to selecting Long-Term Regional Transmission Facilities in Long-Term Regional Transmission Planning, we decline to require

²¹¹⁹ See, e.g., Ameren Initial Comments at 20 (citing NOPR, 179 FERC ¶61,028 at P 242); Vistra Initial Comments at 17–18; WATT Coalition Initial Comments at 9.

²¹²¹ Where transmission providers employ a portfolio approach to evaluating and selecting Long-Term Regional Transmission Facilities, we require only that they include in such a determination the measured benefits for the portfolio of Long-Term Regional Transmission Facilities on an aggregate basis.

²¹²² See, e.g., GridLab Initial Comments at 19; TAPS Initial Comments at 16–17.

transmission providers to use either approach. However, we clarify that transmission providers may not adopt an approach under which they would not select a Long-Term Regional Transmission Facility unless it meets their selection criteria in every Long-Term Scenario and sensitivity. We are concerned that such an approach could impose a threshold for selection that is so onerous it limits selection of most or all Long-Term Regional Transmission Facilities, and, as such, is inconsistent with the requirement that selection criteria seek to maximize benefits accounting for costs over time without over-building transmission facilities. We find that such an approach would not ensure that transmission providers have the opportunity to select Long-Term Regional Transmission Facilities to more efficiently or cost-effectively address Long-Term Transmission Needs, an opportunity that we find, as described in the Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities section above, is necessary to ensure just and reasonable Commission-jurisdictional rates.

969. Again, we emphasize that this final order does not require that transmission providers select any particular Long-Term Regional Transmission Facility (or portfolio of such Facilities). Rather, this final order simply requires transmission providers to adopt an evaluation process and selection criteria that meet the minimum requirements set forth in this final order, including that they aim to maximize benefits accounting for costs over time without over-building transmission facilities. In response to NYISO,²¹²³ however, we decline to clarify the definition of “over-building,” because doing so would limit transmission providers’ flexibility to assess what constitutes over-building in their transmission planning region. Transmission planning regions have a wide variety of market structures, and numerous factors drive transmission needs, which may require evaluation processes and selection criteria that maximize benefits accounting for costs or guard against over-building in different ways. We expect that evaluation processes and selection criteria that maximize benefits accounting for costs over time without over-building transmission facilities will include a variety of features, based on their regional circumstances, that combine to ensure that transmission providers give careful, informed consideration to Long-Term Regional

Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. We also note that, in response to CTC Global’s concerns about the selection criteria being limited to considering regional transmission facilities with the least capital costs,²¹²⁴ we clarify that both estimated benefits and costs must be disclosed when evaluating a Long-Term Regional Transmission Facility for selection and that transmission providers must adopt selection criteria that seek to maximize benefits accounting for costs over time without over-building transmission facilities.

970. In response to Maine Public Advocate,²¹²⁵ we decline to require transmission providers to select non-transmission alternatives where such non-transmission alternatives meet a Long-Term Transmission Need at a lower cost than an alternative Long-Term Regional Transmission Facility. The Commission did not propose to require transmission providers to consider non-transmission alternatives for potential selection in the NOPR, and we are not persuaded to do so in this final order. We note, however, that transmission providers already are required to consider non-transmission alternatives on a comparable basis in regional transmission planning.²¹²⁶

971. Finally, in response to TAPS,²¹²⁷ we decline to require transmission providers to develop affordability metrics to provide along with other information about a particular Long-Term Regional Transmission Facility. The Commission did not propose such a requirement in the NOPR, and we are not persuaded to adopt a requirement for such metrics in this final order.

4. Role of Relevant State Entities

a. NOPR Proposal

972. In the NOPR, the Commission proposed to require that transmission providers, as part of their Long-Term Regional Transmission Planning, include in their OATTs a process to coordinate with the Relevant State Entities in developing selection criteria.²¹²⁸ Regarding this requirement, the Commission proposed to require transmission providers to demonstrate on compliance that they consulted with and sought support from the Relevant State Entities in their transmission

planning region’s footprint to develop their proposed selection criteria.²¹²⁹

b. Comments

i. Support/Oppose

973. Many commenters support the Commission’s proposal to require transmission providers to consult with and seek support from Relevant State Entities²¹³⁰ and include in their OATTs a process to coordinate with the Relevant State Entities²¹³¹ in developing selection criteria. For example, ELCON argues that coordination with Relevant State Entities in identifying selection criteria is critical because it will promote cooperation and could result in more efficient state siting and permitting processes.²¹³² Pennsylvania Commission asserts that requiring consultation will provide states the opportunity to influence regional transmission planning and cost allocation, thereby promoting the public interest and reducing conflicts and disputes on these matters.²¹³³

974. ISO–NE supports the proposal to provide states with a greater role in the selection of transmission facilities.²¹³⁴ Further, ISO–NE argues that, in the context of policy-based planning, states should be responsible for determining whether to select transmission facilities, with ISO–NE playing a supporting, technical role.²¹³⁵ While NESCOE supports the proposal that transmission providers must consult with and seek support from Relevant State Entities within their transmission planning region’s footprint to develop selection criteria, NESCOE requests that the Commission provide Relevant State Entities an expanded role in the selection of transmission projects where the project is identified as needed in response to state laws or policy goals and require transmission providers to include such a role in their OATTs.²¹³⁶

²¹²⁹ *Id.* P 246.

²¹³⁰ See ACEG Initial Comments at 59–60; Ameren Initial Comments at 20; American Municipal Power Initial Comments at 12; California Commission Initial Comments at 37; ELCON Initial Comments at 17; Nebraska Commission Initial Comments at 8–9; North Carolina Commission and Staff Initial Comments at 4–5; Pennsylvania Commission Initial Comments at 10; PJM States Initial Comments at 3.

²¹³¹ See NARUC Initial Comments at 44; NESCOE Initial Comments at 9–10, 46; Pacific Northwest State Agencies Initial Comments at 19; PJM States Initial Comments at 3.

²¹³² ELCON Initial Comments at 17.

²¹³³ Pennsylvania Commission Initial Comments at 10.

²¹³⁴ ISO–NE Initial Comments at 35.

²¹³⁵ *Id.* NESCOE supports ISO–NE’s position. NESCOE Reply Comments at 5 & n.16.

²¹³⁶ NESCOE Initial Comments at 9–10, 48–49.

²¹²³ NYISO Initial Comments at 43.

²¹²⁴ CTC Global Initial Comments at 9.

²¹²⁵ Maine Public Advocate Initial Comments at 1–2.

²¹²⁶ Order No. 1000, 136 FERC ¶ 61,051 at P 148.

²¹²⁷ TAPS Initial Comments at 16–17, 19–20 (citations omitted).

²¹²⁸ NOPR, 179 FERC ¶ 61,028 at P 241.

975. PJM states that it also supports providing additional opportunity for involvement by states and stakeholders in Long-Term Regional Transmission Planning; however, in response to ISO-NE, PJM urges the Commission to make clear that transmission providers retain authority to select transmission facilities and argues that such role is more than a “technical supporting role.”²¹³⁷ PJM States contend that an upfront and transparent process, with substantive state involvement, will ensure that selection criteria are thoroughly discussed by stakeholders and are consistent with the rest of Long-Term Regional Transmission Planning.²¹³⁸

976. New York Commission and NYSEDA state that the Commission should allow Relevant State Entities to be part of the decision-making process regarding the appropriate timeframe for selecting a transmission facility.²¹³⁹

977. California Commission urges the Commission to require that transmission providers indicate in their compliance filings whether the selection criteria they propose are supported by the Relevant State Entities and, if not, to explain any points of disagreement.²¹⁴⁰ PJM States argue that the Commission should, without dictating any substantive outcomes, “recognize the primacy of the role for retail regulators” in the final order.²¹⁴¹ By contrast, ACEG cautions that transmission providers must balance all states’ interests when developing selection criteria instead of maximizing one state’s interest over another’s.²¹⁴² NYISO states that each transmission planning region should have flexibility to determine how it will consult with and seek support from Relevant State Entities regarding selection criteria.²¹⁴³

978. To ensure that consultation is successful, NARUC recommends that the Commission require transmission providers to take two steps: (1) communicate with the Relevant State Entities promptly following issuance of a final order in a manner that is reasonably calculated to be received by the Relevant State Entities; and (2) establish a forum for negotiation that enables full and robust participation by both transmission providers and Relevant State Entities during the period

allotted for making compliance filings.²¹⁴⁴

979. Some commenters oppose the Commission’s NOPR proposal.²¹⁴⁵ Dominion argues that mandating involvement by Relevant State Entities would unnecessarily burden transmission providers.²¹⁴⁶ Louisiana Commission argues that the proposal would represent “superficial state involvement” and serve as “window dressing” for the erosion of state authority due to Long-Term Regional Transmission Planning. Louisiana Commission argues that collective oversight by the states within an RTO/ISO is not equivalent to state oversight of its own retail electric service companies, particularly in circumstances where states are subject to the decisions of the majority.²¹⁴⁷

980. APPA opposes any requirement for transmission providers to consult with, and/or seek the support of, Relevant State Entities in identifying selection criteria.²¹⁴⁸ APPA contends that Relevant State Entities should be considered in the same manner as other stakeholders under the requirements of Order Nos. 890 and 1000.²¹⁴⁹ DC and MD Offices of People’s Counsel disagree with APPA, arguing that the Commission should afford Relevant State Entities an expansive role in the selection of transmission facilities in Long-Term Regional Transmission Planning.²¹⁵⁰ DC and MD Offices of People’s Counsel contend that Relevant State Entities can reach agreement quickly and have access to the best available data used for baseline planning and scenario analysis of transmission facilities.²¹⁵¹

981. MISO takes no position but argues that its existing processes already entail extensive stakeholder engagement, including consulting with state regulatory commissions individually and through OMS, to determine the selection criteria that should be used to maximize long-term transmission value and to ensure an adequate, reliable, and resilient transmission system.²¹⁵²

²¹⁴⁴ NARUC Initial Comments at 44.

²¹⁴⁵ See, e.g., Clean Energy Associations Initial Comments at 22–23 (arguing that, while state involvement should play a role, the Commission should set forth *pro forma* selection criteria).

²¹⁴⁶ Dominion Initial Comments at 37–38.

²¹⁴⁷ Louisiana Commission Initial Comments at 27.

²¹⁴⁸ APPA Initial Comments at 34.

²¹⁴⁹ *Id.*

²¹⁵⁰ DC and MD Offices of People’s Counsel Reply Comments at 9 (citing APPA Initial Comments at 35).

²¹⁵¹ *Id.*

²¹⁵² MISO Initial Comments at 55.

ii. Obtaining/Not Obtaining Consent

982. Several commenters discuss whether transmission providers need only consult with and seek support from Relevant State Entities in the development of selection criteria, or whether they also must obtain their consent.²¹⁵³ For example, Indicated PJM TOs support the NOPR proposal but argue that the Commission should not require transmission providers to obtain the agreement of Relevant State Entities in determining selection criteria.²¹⁵⁴ AEP agrees and argues that state input should be only one factor and that engineering considerations should drive the establishment of selection criteria. AEP also expresses skepticism that requiring transmission providers to consult with Relevant State Entities will increase the chances that states will site the transmission facilities that transmission providers select, because transmission line siting processes will occur years after the establishment of selection criteria, will likely be performed by different personnel, and will address considerations separate from those in establishing selection criteria.²¹⁵⁵

983. Southeast PIOs argue that, while they do not oppose factoring state and consumer support into the selection of transmission facilities, the Commission should not require transmission providers to obtain the approval of Relevant State Entities prior to selection of transmission facilities, because doing so would risk indefinitely delaying Long-Term Regional Transmission Planning.²¹⁵⁶

984. PJM argues that it should be able to develop selection criteria in the event that Relevant State Entities do not agree on the establishment of selection criteria. PJM recommends that the Commission clarify that any requirement to demonstrate that transmission providers have consulted with and sought support from Relevant State Entities could be satisfied even if the transmission provider is unable to secure the agreement of Relevant State Entities.²¹⁵⁷

985. By contrast, NARUC opposes a process in which transmission providers consult with and seek support from Relevant State Entities but are empowered to override or ignore selection criteria proposed and

²¹⁵³ See, e.g., Acadia Center and CLF Initial Comments at 27–28 (arguing that states should have veto authority over transmission providers’ selection criteria in certain circumstances).

²¹⁵⁴ Indicated PJM TOs Initial Comments at 18 (citing NOPR 179, FERC ¶ 61,028 at PP 244, 246).

²¹⁵⁵ AEP Initial Comments at 29–30.

²¹⁵⁶ Southeast PIOs Reply Comments at 27.

²¹⁵⁷ PJM Initial Comments at 104.

²¹³⁷ PJM Reply Comments at 35–36 (citing ISO-NE Initial Comments at 16).

²¹³⁸ PJM States Reply Comments at 8.

²¹³⁹ New York Commission and NYSEDA Initial Comments at 12.

²¹⁴⁰ California Commission Initial Comments at 37–38.

²¹⁴¹ PJM States Initial Comments at 3–4 (citing NOPR, 179 FERC ¶ 61,028 at P 245).

²¹⁴² ACEG Initial Comments at 59–60.

²¹⁴³ NYISO Initial Comments at 44.

supported by Relevant State Entities. NARUC seeks clarification as to what recourse will be available to Relevant State Entities in the event that there is not agreement on selection criteria.²¹⁵⁸ Nebraska Commission argues that the Commission should require transmission providers to demonstrate to the greatest extent possible that they gained the support of Relevant State Entities, because otherwise the process of consulting with and seeking support from Relevant State Entities could become a mere exercise.²¹⁵⁹

986. Mississippi Commission suggests that the Commission require transmission providers to obtain the agreement of Relevant State Entities on selection criteria for Long-Term Regional Transmission Planning.²¹⁶⁰ Southern goes further, arguing that the Commission should allow Relevant State Entities to use the State Agreement Process not only to allocate the costs of Long-Term Regional Transmission Facilities, but also to select such transmission facilities in the first instance. Southern contends that, if the Commission does not allow states to select transmission facilities, the Commission will unlawfully intrude into state jurisdiction over resource planning.²¹⁶¹

987. Acadia Center and CLF assert that states should have the authority to propose selection criteria, arguing that this will ensure that transmission providers do not refuse to consider states' interests and goals regarding transmission needs. Acadia Center and CLF further contend that states should have veto authority over transmission providers' selection criteria in certain scenarios, such as ISO-NE, where a majority of states in a transmission planning region have decarbonization goals but the ISO/RTO continues to apply business-as-usual selection criteria that prioritize reliability and economic considerations.²¹⁶²

988. AEE argues that the final order should clearly provide an opportunity for states to suggest selection criteria and inputs for analyzing transmission projects, noting that such a process may need to be continually developed following issuance of a final order.²¹⁶³

iii. Consultation With Other Entities

989. A number of commenters argue that transmission providers should consult with and seek support from other entities in addition to Relevant State Entities. Large Public Power does not object to the NOPR proposal but argues that it is essential that municipal utilities also be included as participants in the consultative process.²¹⁶⁴

American Municipal Power urges the Commission to recognize that publicly-owned utilities play a role analogous to state commissions, in that they are publicly accountable, operate through open and transparent procedures, and adopt policies reflecting the consensus of communities that own and support them. American Municipal Power argues that FPA section 217(b)(4) requires the Commission to revise the NOPR proposal such that load-serving entities, including publicly-owned utilities, are on a par with Relevant State Entities.²¹⁶⁵ NRECA agrees, arguing that Relevant State Entities may not have regulatory authority over electric cooperatives, and therefore the Commission must modify its proposal to include consultation with load-serving entities to conform with FPA section 217(b)(4) and Order No. 1000's transmission planning principles.²¹⁶⁶

990. Relatedly, NARUC argues that nothing in the final order should inhibit states from permitting the participation of certain quasi-public/private state and Federal entities or other state entities in addition to Relevant State Entities.²¹⁶⁷ NEPOOL states that the selection of any transmission facilities should be made with substantial input from both market participant stakeholders and the transmission planning region's states.²¹⁶⁸

iv. Practical Implementation Issues

991. Several commenters discuss practical issues with the requirement that transmission providers consult with and seek the support of Relevant State Entities in developing selection criteria. For example, PPL generally supports the Commission's proposal but contends that some states may find it difficult to fulfill the role described in the NOPR. PPL therefore argues that the Commission should allow transmission providers flexibility in developing consultative processes.²¹⁶⁹ AEP argues

that some states will be unable to participate effectively given a lack of resources or statutory limitations, such that the consultative process may result in selection criteria "that unfairly or unreasonably emphasize certain values."²¹⁷⁰ NESCOE states that the Commission should provide flexibility as to how states elect to engage in the transmission planning process, noting that a state official's role in siting electric infrastructure may make it preferable for a different state official to provide that state's view on certain aspects of Long-Term Regional Transmission Planning, such as transmission project selection.²¹⁷¹

992. NEPOOL requests that the Commission articulate principles for who should make selection decisions when a Long-Term Regional Transmission Facility may address transmission needs driven by reliability, economics, and public policy.²¹⁷²

993. Michigan State Entities argue that the success of the Commission's proposed reforms depends on transmission providers meaningfully engaging with stakeholders, which requires that stakeholders have the time and capability to participate in a stakeholder review process. Michigan State Entities further assert that stakeholders representing diffuse and broad interests (e.g., residential ratepayers), as opposed to concentrated interests, tend to have fewer resources with which to fund participation in these processes, noting that many states have created consumer advocacy agencies to correct this imbalance. Michigan State Entities assert that the Commission should require that transmission providers include RTO/ISO-level, publicly funded consumer advocates in the stakeholder processes that are empowered to participate in approving selection criteria.²¹⁷³

c. Commission Determination

994. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consult with and seek support from Relevant State Entities regarding the evaluation process, including selection criteria, that transmission providers propose to use to identify and evaluate Long-Term Regional Transmission Facilities for selection. Specifically, we require transmission providers to demonstrate on compliance that they made good

²¹⁵⁸ NARUC Initial Comments at 45.

²¹⁵⁹ Nebraska Commission Initial Comments at 8–9.

²¹⁶⁰ Mississippi Commission Initial Comments at 3–4 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 11)).

²¹⁶¹ Southern Initial Comments at 6–10 & n.12 (citations omitted).

²¹⁶² Acadia Center and CLF Initial Comments at 27–28.

²¹⁶³ AEE Initial Comments at 30–32 (citations omitted).

²¹⁶⁴ Large Public Power Initial Comments at 30.

²¹⁶⁵ American Municipal Power Initial Comments at 12–13.

²¹⁶⁶ NRECA Initial Comments at 50.

²¹⁶⁷ NARUC Initial Comments at 29–30 (citation omitted).

²¹⁶⁸ NEPOOL Initial Comments at 8.

²¹⁶⁹ PPL Initial Comments at 18–19.

²¹⁷⁰ AEP Initial Comments at 30 (quoting NOPR, 179 FERC ¶ 61,028 at P 290).

²¹⁷¹ NESCOE Initial Comments at 9 n.16.

²¹⁷² NEPOOL Initial Comments at 8.

²¹⁷³ Michigan State Entities Initial Comments at 4–5.

faith efforts to consult with and seek support from Relevant State Entities in their transmission planning region's footprint when developing the evaluation process and selection criteria that they propose to include in their OATTs.²¹⁷⁴

995. We decline to adopt the NOPR proposal to require transmission providers to include in their OATTs a process for coordinating with Relevant State Entities. We believe that the requirement adopted in this final order will simplify compliance efforts without sacrificing the benefits of consulting with and seeking the support of Relevant State Entities. We disagree with Dominion that requiring transmission providers to consult with and seek support from Relevant State Entities will prove burdensome, and we believe that our decision not to require transmission providers to include a process for such consultation in their OATTs will further reduce any administrative burden of this requirement.²¹⁷⁵

996. We clarify that we require transmission providers to seek support from Relevant State Entities, but do not require transmission providers to obtain their support, before proposing an evaluation process and selection criteria on compliance.²¹⁷⁶ In response to Acadia Center and CLF, we note that Relevant State Entities may propose selection criteria to transmission providers, but ultimately, it is transmission providers who must propose on compliance an evaluation process and selection criteria that comply with the requirements of this final order. We further note that providing states with veto authority over transmission providers' proposed selection criteria would be akin to requiring transmission providers to obtain the support of Relevant State Entities, and therefore we do not adopt Acadia Center and CLF's recommendation.²¹⁷⁷ While we believe that Long-Term Regional Transmission Planning is more likely to be successful where transmission providers, Relevant State Entities, and other stakeholders collaborate to develop an evaluation

process and selection criteria, we reiterate that transmission planning is the tariff obligation of each transmission provider and transmission providers retain ultimate responsibility for regional transmission planning, including Long-Term Regional Transmission Planning, as well as complying with the obligations of this final order.²¹⁷⁸ Moreover, we acknowledge that achieving consensus may not be possible in every instance.

997. We disagree with NARUC that, in the absence of a requirement that transmission providers obtain the support of Relevant State Entities, transmission providers will be empowered to ignore the input of Relevant State Entities. In this final order, we require transmission providers to make good faith efforts to consult with and seek the support of Relevant State Entities. We do not agree that the failure to obtain the support of Relevant State Entities is necessarily evidence that transmission providers did not exercise good faith efforts to seek their support.

998. For similar reasons, we also disagree with Louisiana Commission when it argues that requiring transmission providers to simply consult with and seek support from Relevant State Entities will amount to only superficial state involvement in the development of an evaluation process and selection criteria.²¹⁷⁹ In response to Louisiana Commission's additional contention that collective oversight of regional transmission planning processes by the transmission planning region's states is not equivalent to state oversight of its own retail electric service companies, we reiterate that this final order requires transmission providers to engage in and conduct sufficiently long-term, forward-looking, and comprehensive transmission planning and cost allocation processes to identify and plan for Long-Term Transmission Needs in order to ensure *Commission-jurisdictional* rates are just and reasonable. As discussed in the Legal Authority to Adopt Reforms for Long-Term Regional Transmission Planning section, the final order neither aims at nor conflicts with state authority over retail rates.

999. We do not believe that it is necessary to adopt California Commission's proposal to require transmission providers to indicate in

their compliance filings whether Relevant State Entities support the proposal or explain any points of disagreement that they may have with Relevant State Entities. Relevant State Entities may intervene in compliance filing proceedings and provide this information for the Commission's consideration as it determines whether transmission providers have met the requirements that we adopt in this final order. Nor do we adopt NARUC's request that we impose specific requirements dictating how transmission providers should consult with and seek the support of Relevant State Entities beyond the requirement that they demonstrate good faith efforts to do so. We believe that it is appropriate to provide transmission providers with flexibility in how to consult with and seek support of Relevant State Entities based on the specific needs and makeup of their transmission planning region. Further, we acknowledge, as argued by some commenters,²¹⁸⁰ that practical or legal limitations may limit the extent to which some Relevant State Entities may participate in such processes, reinforcing the need for flexibility.

1000. We clarify that nothing in this final order diminishes the role of stakeholders that are not Relevant State Entities, nor absolves transmission providers of any existing obligations that they may have to provide opportunities for stakeholder input.²¹⁸¹ That said, we decline to require transmission providers to consult with or seek support from entities in addition to Relevant State Entities, including load-serving entities.²¹⁸² This final order recognizes that Relevant State Entities play a unique role in representing the interests of states, which retain a variety of authorities, including those under FPA section 201, that are integral to the success of Long-Term Regional Transmission Planning.

1001. Further, we disagree with American Municipal Power that FPA section 217(b)(4) requires that this final order treat load-serving entities on par with Relevant State Entities. Through the requirements of this final order, we seek to ensure that adequate

²¹⁷⁴ In response to New York Commission and NYSEDA, we note that such consultation may include discussion of the appropriate timeframe for selecting a Long-Term Regional Transmission Facility. New York Commission and NYSEDA Initial Comments at 12.

²¹⁷⁵ See Dominion Initial Comments at 37–38.

²¹⁷⁶ See, e.g., PJM Initial Comments at 104 (requesting clarification that transmission providers are permitted to submit an evaluation process and selection criteria on compliance in the absence of obtaining the support of Relevant State Entities).

²¹⁷⁷ See Acadia Center and CLF Initial Comments at 27–28.

²¹⁷⁸ See Order No. 1000, 136 FERC ¶ 61,051 at P 153 (“[T]he ultimate responsibility for transmission planning remains with public utility transmission providers.” (citing Order No. 890, 118 FERC ¶ 61,119 at P 454)).

²¹⁷⁹ Louisiana Commission Initial Comments at 27.

²¹⁸⁰ See AEP Initial Comments at 30 (quoting NOPR, 179 FERC ¶ 61,028 at P 290); NESCOE Initial Comments at 9 n.16; PPL Initial Comments at 18–19.

²¹⁸¹ In response to NARUC and NEPOOL, see NARUC Initial Comments at 29–30; NEPOOL Initial Comments at 9, we reiterate that this may include other state entities in addition to Relevant State Entities, such as Federal entities, market participants, and other stakeholders.

²¹⁸² See, e.g., American Municipal Power Initial Comments at 12–13; Large Public Power Initial Comments at 30.

transmission capacity is built to allow load-serving entities to meet their service obligations and facilitate the planning of a reliable grid, consistent with FPA section 217(b)(4). Nothing in our determination to require transmission providers to consult with and seek support from Relevant State Entities (but not load-serving entities) changes that aim or undercuts the ability of Long-Term Regional Transmission Planning to achieve it. We continue to find that other requirements in the final order, including the requirement to incorporate state-approved integrated resource plans and expected supply obligations for load-serving entities in the development of Long-Term Scenarios, ensure load-serving entities' reasonable needs for transmission capacity to meet their service obligations are incorporated into Long-Term Regional Transmission Planning.

1002. Finally, in response to commenters,²¹⁸³ we clarify that transmission providers, not Relevant State Entities, must determine whether or not to select Long-Term Transmission Facilities to meet Long-Term Transmission Needs. Under the FPA, the Commission has jurisdiction over transmission providers, and those entities, not Relevant State Entities, are subject to the requirements of this final order. As discussed above in the Transparent and Not Unduly Discriminatory; More Efficient or Cost-Effective Transmission Facilities section, we require herein that transmission providers designate a point in the evaluation process at which they will determine whether to select or not select identified Long-Term Regional Transmission Facilities (or portfolio of such Facilities).

5. Voluntary Funding Opportunities

a. NOPR Proposal

1003. In the NOPR, the Commission sought comment on whether Relevant State Entities should have the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-

Term Regional Transmission Facility to enable such facility to meet transmission providers' selection criteria (e.g., any benefit-cost threshold), and if so, what mechanism would be appropriate to document such voluntary funding agreements, how transmission providers would be assured that commitments to provide funding would be sufficiently binding, and what the most appropriate point would be in the process for such voluntary commitments.²¹⁸⁴ The Commission also sought comment on whether such a voluntary funding opportunity should be extended to other entities, such as interconnection customers.²¹⁸⁵

b. Comments

1004. Of commenters that address the question posed in the NOPR regarding whether Relevant State Entities should have the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility, nearly all argue that the Commission should allow such an opportunity.²¹⁸⁶ ISO-NE argues that the Commission should provide flexibility to transmission providers to determine the specific means for documenting the state's agreement to provide such funding.²¹⁸⁷ APPA argues that the Commission should require the filing under FPA section 205 of agreements to fund the cost of, or a portion of the cost of, a transmission facility so that affected parties have an opportunity to comment.²¹⁸⁸

1005. Grid United argues that, while it supports *ex ante* cost allocation methods, the Commission also should

continue to permit alternative cost recovery arrangements, including participant funding agreements and voluntary agreements entered into by generation developers and Relevant State Entities.²¹⁸⁹ Duke asserts that the Commission should avoid prescriptive rules that discourage or undervalue voluntary funding from transmission providers, states, Relevant State Entities, or interconnection customers.²¹⁹⁰ Xcel argues that the Commission should state in a final order that neither the FPA nor the Commission's rules and regulations forbid voluntary arrangements for planning and paying for transmission facilities.²¹⁹¹

1006. NARUC argues that the final order should not inhibit the flexibility of Relevant State Entities in developing approaches to such voluntary funding commitments.²¹⁹² NARUC argues that the final order should be as flexible as possible in providing voluntary funding opportunities to account for the variety of state laws enabling such authority and to allow for the possibility of sharing the costs of such transmission facilities between load and generator developers.²¹⁹³

1007. Louisiana Commission supports the NOPR proposal and argues that voluntary agreement is the only fair, reasonable, and just way to allocate the costs of transmission facilities selected in Long-Term Regional Transmission Planning.²¹⁹⁴ Ameren believes that Relevant State Entities should have the opportunity to fund a portion of the cost of a transmission facility that otherwise would not meet the OATT selection criteria but requests that the Commission clarify that this decision "is referring to cost allocation."²¹⁹⁵ Ameren argues that without this clarification, Relevant State Entities could fund part of the transmission facility while imposing on a transmission owner the obligation to operate and maintain that facility and assure regulatory compliance without adequate compensation, in violation of the D.C. Circuit's determination in *Ameren Services Co. v. FERC* that transmission owners "should not be forced to operate as a non-profit."²¹⁹⁶

²¹⁸³ See, e.g., ISO-NE Initial Comments at 35 (arguing that states should be responsible for determining whether to select transmission facilities and that transmission providers should play a supportive, technical role); NEPOOL Initial Comments at 8 (requesting that the Commission articulate principles for who should select multi-value transmission facilities); NESCOE Initial Comments at 9, 48–49 (requesting that the Commission require transmission providers to include a role in their OATTs for Relevant State Entities in the selection of Long-Term Regional Transmission Facilities); PJM Reply Comments at 36 (requesting that the Commission clarify that transmission providers retain the authority to select transmission facilities).

²¹⁸⁴ NOPR, 179 FERC ¶ 61,028 at P 252. The Commission stated that, for Long-Term Regional Transmission Facilities, such an opportunity for the Relevant State Entities could enable them to assign a value to achieving their particular policy goals while ensuring that their customers bear the corresponding costs. *Id.* P 252 n.399.

²¹⁸⁵ *Id.*

²¹⁸⁶ See Ameren Initial Comments at 21; APPA Initial Comments at 34–35; Clean Energy Associations Initial Comments at 23; Duke Initial Comments at 28–29; Grid United Initial Comments at 6; Idaho Commission Initial Comments at 5; ISO-NE Initial Comments at 36; Louisiana Commission Initial Comments at 29; NARUC Initial Comments at 31–32 (citing *MISO-SPP Joint Targeted Interconnection Queue Study (JTIQ)*, MISO, <https://www.misoenergy.org/engage/committees/miso-spp-joint-targeted-interconnection-queue-study/>); New Jersey Commission Initial Comments at 25; PPL Initial Comments at 19; SDG&E Initial Comments at 4; WATT Coalition Initial Comments at 11; Xcel Initial Comments at 14 (stating that neither the FPA nor the Commission's rules and regulations categorically preclude voluntary agreement to plan and pay for new transmission facilities (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 146, 561, 724; *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at P 3)).

²¹⁸⁷ ISO-NE Initial Comments at 36.

²¹⁸⁸ APPA Initial Comments at 34–35 (citing *PJM Interconnection, LLC*, 179 FERC ¶ 61,024 (2022)).

²¹⁸⁹ Grid United Initial Comments at 6.

²¹⁹⁰ Duke Initial Comments at 28–29.

²¹⁹¹ Xcel Initial Comments at 14.

²¹⁹² NARUC Initial Comments at 31–32; *accord* Idaho Commission Initial Comments at 5.

²¹⁹³ NARUC Initial Comments at 32.

²¹⁹⁴ Louisiana Commission Initial Comments at 29.

²¹⁹⁵ Ameren Initial Comments at 21–22 (citing NOPR, 179 FERC ¶ 61,028 at P 252).

²¹⁹⁶ *Id.* (citing *Ameren Servs. Co. v. FERC*, 880 F.3d 571 (D.C. Cir. 2018)).

1008. Clean Energy Associations suggest two mechanisms to provide opportunities for states and interconnection customers to ensure that necessary transmission facilities are built. First, Clean Energy Associations would provide a “Transmission Alternative Right,” through which states or interconnection customers could pay the difference between evaluated benefits and the level of benefits necessary to meet the applicable benefits threshold. Second, Clean Energy Associations would provide a “Transmission Expansion Right,” which would allow states or interconnection customers to provide funding to expand transmission facilities beyond those identified in Long-Term Regional Transmission Planning. With respect to this second right, Clean Energy Associations contend that the funding parties should receive time-limited priority usage of additional transmission expansion that they fund and retain incremental capacity attributes associated with the expanded capability.²¹⁹⁷ Clean Energy Associations also suggest that the portion of the expanded Long-Term Regional Transmission Facility originally identified in the regional transmission plan would receive the applicable regional cost allocation.²¹⁹⁸

1009. New Jersey Commission argues that allowing Relevant State Entities the opportunity to fund the cost of or part of the cost of transmission facilities would provide a way to value a transmission facility’s public policy benefits and a mechanism for co-optimizing reliability and economic benefits while meeting public policy needs. However, New Jersey Commission states that, while the proposed 20-year transmission planning horizon should ensure that transmission providers identify opportunities for multi-driver transmission projects in sufficient time for states to provide funding, the Commission should mandate that transmission providers reach out to Relevant State Entities to inform them of such opportunities on a timely basis.²¹⁹⁹

1010. SPP takes no position on the voluntary funding issue but states that

its Regional State Committee developed a cost allocation framework that includes the option for entities to sponsor specific transmission projects, assuming cost responsibility without imposing burdens on others through the general rate structure. SPP states that this mechanism could be used by a state or states to fund projects that SPP otherwise would not select.²²⁰⁰

1011. While PPL supports the ability of states to fund the cost of, or a portion of the costs of, transmission facilities that otherwise would not meet selection criteria, PPL argues that the final order should not require transmission providers to facilitate such an opportunity with states.²²⁰¹ APS contends that it is not appropriate for a Relevant State Entity to volunteer its ratepayers to fund, and APS to build, a transmission facility. APS explains that Arizona is a diverse state with several non-jurisdictional entities; as such, APS contends that the state would not have the authority to volunteer all the state’s ratepayers to fund the transmission facility, which ultimately may burden transmission providers with additional costs and responsibilities.²²⁰²

c. Commission Determination

1012. We modify the NOPR proposal and require transmission providers in each transmission planning region to include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers’ selection criteria. We provide transmission providers with the flexibility to propose certain features of such a voluntary funding process in their compliance filings.²²⁰³ However, this voluntary funding process must be transparent and not unduly discriminatory or preferential and provide for the four components discussed below. Further, as with other aspects of the evaluation process and selection criteria, transmission providers must consult with and seek support from Relevant State Entities when developing a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of,

a Long-Term Regional Transmission Facility that they propose to include in their OATTs.

1013. In setting forth the requirement that transmission providers include in their OATTs a process to provide Relevant State Entities and interconnection customers with the opportunity to voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility that otherwise would not meet the transmission providers’ selection criteria, we direct transmission providers to propose OATT provisions on compliance that describe: (1) the process by which the transmission providers will make voluntary funding opportunities available to Relevant State Entities and interconnection customers, which must ensure that Relevant State Entities and interconnection customers receive timely notice of such opportunities and provide a meaningful opportunity for Relevant State Entities and interconnection customers; (2) the period during which Relevant State Entities and interconnection customers may exercise the option to provide voluntary funding; (3) the method that transmission providers will use to determine the amount of voluntary funding required to ensure that the Long-Term Regional Transmission Facility meets the transmission providers’ selection criteria; and (4) the mechanism through which transmission providers and Relevant State Entities or interconnection customers will memorialize any voluntary funding agreement, *e.g.*, a *pro forma* agreement in the OATT. We clarify that, for any portion of the costs of a selected Long-Term Regional Transmission Facility that is *not* voluntarily funded by a Relevant State Entity (or Entities) or interconnection customers, those remaining costs must be allocated according to the applicable Long-Term Regional Transmission Cost Allocation Method (or cost allocation method resulting from a State Agreement Process, if such a process is adopted by the transmission providers in the associated transmission planning region).

1014. We believe that requiring transmission providers to include a voluntary funding process in their OATTs ultimately may increase the number of Long-Term Regional Transmission Facilities that are selected. The voluntary funding processes that we are requiring transmission providers to include in their OATTs will allow Relevant State Entities and interconnection customers to voluntarily fund the cost of, or a portion of the cost of, a Long-Term

²¹⁹⁷ Clean Energy Associations Initial Comments at 23–24 (citing Clean Energy Associations ANOPR Initial Comments at 76). Clean Energy Associations assert this would be consistent with Order No. 807. *Id.* (citing Clean Energy Associations ANOPR Initial Comments at 76–78; *Open Access & Priority Rights on Interconnection Customer’s Interconnection Facilities*, Order No. 807, 150 FERC ¶ 61,211, at P 109, *order on reh’g*, Order No. 807–A, 153 FERC ¶ 61,047 (2015)).

²¹⁹⁸ *See id.*

²¹⁹⁹ New Jersey Commission Initial Comments at 28.

²²⁰⁰ SPP Initial Comments at 22 (citing SPP, *Governing Documents Tariff, Bylaws, First Revised Volume No. 4* (0.0.0), § 7.2).

²²⁰¹ PPL Initial Comments at 19.

²²⁰² APS Initial Comments at 10.

²²⁰³ *See* ISO–NE Initial Comments at 36; NARUC Initial Comments at 31–32 (requesting flexibility to design voluntary funding processes).

Regional Transmission Facility, with any remaining costs allocated to beneficiaries in a manner that is at least roughly commensurate with the estimated benefits that they will receive. As such, a voluntary funding process will allow the development of Long-Term Regional Transmission Facilities that Relevant State Entities or interconnection customers believe are beneficial but that might not otherwise be selected.²²⁰⁴ We also believe that such a voluntary funding process could help transmission providers to avoid, manage, or resolve otherwise difficult disputes among stakeholders in their transmission planning regions, such as those arising from situations in which Relevant State Entities or interconnection customers value the development of certain Long-Term Regional Transmission Facilities differently.

1015. We acknowledge, consistent with APS's comments, that in certain states Relevant State Entities may not have the necessary authority to require all of that state's ratepayers to provide the funding needed to take advantage of voluntary funding opportunities.²²⁰⁵ We do note, however, nothing in this final order is intended to limit, preempt, or otherwise affect state or local laws or regulations with respect to the ability of any Relevant State Entity to voluntarily fund any costs of a Long-Term Regional Transmission Facility. Whether and to what extent a Relevant State Entity chooses to take advantage of an opportunity to voluntarily fund the costs of a Long-Term Regional Transmission Facility is dependent on whether that entity has the requisite authority to do so.

1016. In response to Ameren,²²⁰⁶ we decline to determine at this point what effect *Ameren Services Co. v. FERC* may have on voluntary funding arrangements or the allocation of the costs of a transmission facility net of that voluntary funding, which may depend on how transmission providers propose to allow for voluntary funding opportunities.

1017. We decline Clean Energy Associations' request that we require transmission providers to allow voluntary funding opportunities to expand a Long-Term Regional Transmission Facility beyond what was identified through Long-Term Regional

Transmission Planning (e.g., voluntarily funding the construction of a 500 kV transmission line where a 345 kV transmission line was identified through Long-Term Regional Transmission Planning).²²⁰⁷ While we recognize that there may be interest in providing additional opportunities for voluntary funding, we find that there is insufficient record evidence to support imposing this modification to the voluntary funding opportunity we require in this final order. We note, however, that nothing in this final order prohibits this type of voluntary funding approach and transmission providers may either seek to demonstrate that a proposal including such an approach is consistent with or superior to what is required by this order, or else submit a filing under FPA section 205 to propose the inclusion in their OATTs of voluntary funding opportunities that go beyond those required in this final order.

1018. Finally, in response to APPA,²²⁰⁸ we decline to impose any specific requirement for transmission providers to file agreements that memorialize voluntary funding arrangements under FPA section 205. The Commission will evaluate on compliance the mechanism that transmission providers propose for memorializing voluntary funding agreements between transmission providers and Relevant State Entities or interconnection customers, as applicable.

6. No Selection Requirement

a. NOPR Proposal

1019. The Commission did not propose in the NOPR to require that transmission providers select transmission facilities, even in the event that a transmission facility meets the selection criteria established by the transmission providers.²²⁰⁹

b. Comments

1020. Many commenters express opposition to any potential requirement under which the Commission would require transmission providers to select Long-Term Regional Transmission

Facilities.²²¹⁰ For example, ISO-NE states that the final order should be clear that transmission providers are not required to select any identified Long-Term Regional Transmission Facilities for inclusion in system plans or cost allocation purposes, and NESCOE agrees.²²¹¹ Ameren contends that a mandate to select any transmission facility may result in over-building the transmission system.²²¹² Xcel makes a similar point, arguing that it would result in a loss of confidence in the transmission planning process. Furthermore, Xcel argues, transmission planning is subjective and removing all discretion from transmission planners would result in bad outcomes.²²¹³

1021. SERTP Sponsors urge the Commission to make clear that there is no requirement for transmission providers to select Long-Term Regional Transmission Facilities based on long-term studies without specific express support and agreement of the relevant regulatory authorities and policy makers.²²¹⁴ NRECA asserts that transmission planning using a 20-year transmission planning horizon is an exercise fraught with uncertainty, and requests that the Commission clarify that it is not mandating that transmission providers select Long-Term Regional Transmission Facilities 20 years in advance.²²¹⁵ NRECA states that other commenters also expressed concerns about risks to consumers associated with selecting transmission projects in the regional transmission plan for purposes of cost allocation 20 years before they may be needed.²²¹⁶

²²¹⁰ See, e.g., California Water Initial Comments at 14–15; Dominion Initial Comments at 18; Dominion Reply Comments at 8 (citing NARUC Initial Comments at 5–6, 39); ISO-NE Initial Comments at 35–36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 10)); NESCOE Initial Comments at 46–47; NRECA Initial Comments at 48; NRECA Reply Comments at 4–8 (citations omitted); NYISO Initial Comments at 44 (citing *N.Y. Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,044, at P 125 (2014)); TANC Initial Comments at 10.

²²¹¹ ISO-NE Initial Comments at 35–36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm'r, concurring at P 10)); NESCOE Reply Comments at 5 (citing ISO-NE Initial Comments at 35–36).

²²¹² Ameren Initial Comments at 13 (citing Large Public Power Initial Comments at 10).

²²¹³ Xcel Initial Comments at 13–14.

²²¹⁴ SERTP Sponsors Initial Comments at 5; see also Alabama Commission Initial Comments at 3 (contending that Long-Term Regional Transmission Planning should not involve selection or construction obligations unless the affected state regulators support such actions).

²²¹⁵ NRECA Initial Comments at 27, 48.

²²¹⁶ NRECA Reply Comments at 4–8 (citing APPA Initial Comments at 22, 24–36; California Municipal Utilities Initial Comments at 2–3, 5–7, 15; ELCON Initial Comments at 10; Large Public Power Initial Comments at 6–8, 11–13; Nebraska Commission Initial Comments at 2; New York Commission and

²²⁰⁴ See, e.g., New Jersey Commission Initial Comments at 25–26 (arguing that voluntary funding would provide a way to value a transmission facility's public policy benefits and a mechanism for co-optimizing reliability and economic benefits while meeting public policy needs).

²²⁰⁵ APS Initial Comments at 10.

²²⁰⁶ Ameren Initial Comments at 21–22.

²²⁰⁷ Clean Energy Associations Initial Comments at 23–24 (citations omitted).

²²⁰⁸ APPA Initial Comments at 34–35 (citing *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024).

²²⁰⁹ See NOPR, 179 FERC ¶ 61,028 at P 9 (noting that the proposed reforms related to regional transmission planning and cost allocation requirements, like those of Order Nos. 890 and 1000, are focused on the transmission planning process, and not on any substantive outcomes that may result from this process); see also *id.* P 241 (requiring transmission providers to propose selection criteria to identify and evaluate transmission facilities for *potential selection*).

1022. Dominion claims that Long-Term Regional Transmission Planning should not be a mandated development and construction plan of transmission facilities and argues that it should instead merely be a tool to help transmission providers understand where transmission needs may exist now and in the future.²²¹⁷

1023. PJM requests that the Commission clarify that transmission providers can identify trends across multiple Long-Term Regional Transmission Planning cycles without needing to select specific transmission facilities, arguing that it should have the flexibility to open solicitations for transmission facilities as system needs arise.²²¹⁸

1024. A few commenters favor selection mandates in at least some circumstances. For example, Eversource argues that the Commission should consider requiring transmission providers to address transmission needs that are identified in multiple Long-Term Scenarios or in the “high-impact, low-frequency event” scenario. Eversource contends that transmission providers otherwise risk failing to select transmission facilities that will greatly increase reliability, resiliency, and affordability.²²¹⁹

1025. PIOs state that experience with Order No. 1000 demonstrates that some transmission providers may only do the bare minimum to comply and therefore may fail to select, allocate the costs of, or construct much needed transmission. As such, PIOs state, the Commission should require transmission providers to use good faith efforts to select recommended transmission facilities.²²²⁰

c. Commission Determination

1026. The Commission did not propose in the NOPR, and we will not require in this final order, that transmission providers select any particular Long-Term Regional Transmission Facility—even where a particular transmission facility meets the transmission providers’ selection criteria in their OATTs.²²²¹ This final

order improves regional transmission planning processes by ensuring that transmission providers identify Long-Term Transmission Needs, identify Long-Term Regional Transmission Facilities that resolve those needs and assess the benefits thereof, and provide the opportunity for transmission providers to select such Long-Term Regional Transmission Facilities. In other words, as in Order No. 1000, our focus is on ensuring that regional transmission planning processes result in just and reasonable rates, and not on requiring that these processes achieve any particular substantive outcome.

1027. We believe that transmission providers implementing Long-Term Regional Transmission Planning and developing regional transmission plans require the flexibility to balance competing interests in the transmission planning region and to exercise engineering judgment to ensure the reliable operation of the transmission system and compliance with a variety of regulatory requirements.

1028. We clarify that nothing in this final order prohibits transmission providers from proposing to impose upon themselves a requirement to select a Long-Term Regional Transmission Facility in certain circumstances. For example, transmission providers might propose selection criteria that would require them to select a Long-Term Regional Transmission Facility if it would meet a Long-Term Transmission Need that appears in multiple Long-Term Scenarios, or if it exceeded selection criteria by a pre-set margin.

7. Other Issues

a. Comments

1029. Clean Energy Associations argue that any transmission projects that are approved at the end of a transmission planning cycle should be included in updated models in the next transmission planning cycle, as well as in generation interconnection studies.²²²²

1030. R Street argues that the status quo selection process undermines the NOPR’s objective of advancing efficient and cost-effective transmission expansion and that many transmission projects, especially reliability projects, are not subject to economic scrutiny. Therefore, R Street argues that the Commission should require that all transmission projects pass a cost-benefit analysis under the purview of an independent transmission planner and/

or monitor across all Order No. 1000 transmission planning regions.²²²³

b. Commission Determination

1031. In response to Clean Energy Associations, we clarify that we are not imposing specific requirements regarding the treatment of selected Long-Term Regional Transmission Facilities in subsequent Long-Term Regional Transmission Planning cycles, beyond the overall requirements discussed in the Development of Long-Term Scenarios section of this final order. As we explain above, selection is only one of a number of steps in the transmission development process, and we believe that it is appropriate to provide transmission providers flexibility on how to update their planning models in a manner that most effectively addresses the specifics of their regional transmission planning processes, consistent with the requirements of this final order.

1032. Finally, we note that this final order generally does not require transmission providers to replace or otherwise make changes to existing Order No. 1000 regional reliability and economic transmission planning and cost allocation processes. As such, we decline to adopt R Street’s proposal to require that all transmission projects pass a cost-benefit analysis.

8. Reevaluation

a. NOPR Proposal

1033. The Commission proposed in the NOPR that, consistent with Order No. 1000, the developer of a transmission facility selected through Long-Term Regional Transmission Planning to address transmission needs driven by changes in the resource mix and demand would be eligible to use the applicable cost allocation method for the Long-Term Regional Transmission Facility. The Commission proposed that the existing transmission developer requirements would apply, including that the developer of the selected regional transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals necessary to develop and construct the transmission facility such that it meets the transmission needs of the transmission planning region.²²²⁴ The Commission

NYSERDA Initial Comments at 8, 11–12; Pennsylvania Commission Initial Comments at 4–5; PJM Initial Comments at 59–62; TANC Initial Comments at 10).

²²¹⁷ Dominion Reply Comments at 8 (citing PIOs Initial Comments at 13, 28; NARUC Initial Comments at 5–6, 39).

²²¹⁸ PJM Reply Comments at 36–37.

²²¹⁹ Eversource Initial Comments at 26 (citing NOPR, 179 FERC ¶ 61,028 at P 124).

²²²⁰ PIOs Initial Comments at 12–13.

²²²¹ See, e.g., ISO-NE Initial Comments at 35–36 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm’r, concurring at P 10)); NESCOE Reply Comments at 5 (citing ISO-NE Initial Comments at 35–36); SERTP Sponsors Initial Comments at 5.

²²²² Clean Energy Associations Initial Comments at 10.

²²²³ R Street Initial Comments at 10.

²²²⁴ NOPR, 179 FERC ¶ 61,028 at P 247 (citing Order No. 1000–A, 139 FERC ¶ 61,132 at P 442). The Commission also stated in Order No. 1000–A that, as part of the ongoing monitoring of the progress of a transmission facility once it is selected, the transmission providers in a transmission planning region must establish a date

proposed that, to the extent the Relevant State Entities in a transmission planning region agree to a State Agreement Process, as described in the Regional Transmission Cost Allocation section, the development schedule should also include relevant steps related to that process.²²²⁵

1034. The Commission noted that, given the longer-term nature of transmission needs driven by changes in the resource mix and demand, the required development schedule for a transmission facility selected may make it unnecessary for the developer to take actions or incur expenses in the near-term if the transmission facility will not need to be in service in the near-term. The Commission also noted that a transmission provider may make that Long-Term Regional Transmission Facility's selection status subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles, such that the previously selected transmission facility is no longer needed. The Commission proposed that transmission providers include in their selection criteria how they will address the selection status of a previously selected transmission facility based on the outcomes of subsequent Long-Term Regional Transmission Planning cycles.²²²⁶

b. Comments

1035. Some commenters argue that the Commission should allow or require transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcomes of subsequent Long-Term Regional Transmission Planning cycles.²²²⁷ For example, Kansas Commission contends that transmission providers should be able to de-select any transmission facility selected through Long-Term Regional Transmission Planning if other regional transmission planning processes do not establish a need for that transmission facility.²²²⁸ Illinois Commission argues that periodic review and revision of the underlying modeling assumptions incorporated in Long-Term Scenarios

by which state approvals to construct must have been achieved that is tied to when construction must begin to timely meet the need that the facility is selected to address. If such critical steps have not been achieved by that date, then the transmission providers in a transmission planning region may "remove the transmission project from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution." Order 1000–A, 139 FERC ¶ 61,132 at P 442.

²²²⁵ NOPR, 179 FERC ¶ 61,028 at P 247.

²²²⁶ *Id.* P 248.

²²²⁷ See, e.g., Ameren Initial Comments at 20–21 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

²²²⁸ Kansas Commission Initial Comments at 14.

will help to ensure that Long-Term Regional Transmission Planning allows transmission providers the opportunity to modify regional transmission plans.²²²⁹

1036. APPA supports the NOPR proposal, stating that "off ramps" from Long-Term Regional Transmission Planning are necessary to protect customers from the costs of transmission facilities that are rendered unneeded or inefficient by material changes in available resources, technology, load characteristics, or laws.²²³⁰ APPA continues that the Commission should also require transmission providers to include in their selection criteria how they will address the selection status of previously selected transmission facilities in subsequent transmission planning cycles. APPA further argues that, to facilitate such review, the Commission should require transmission providers to have clear mechanisms for tracking costs and benefits of Long-Term Regional Transmission Facilities and to file periodic cost tracking reports with the Commission so that stakeholders have an opportunity to comment.²²³¹

1037. LS Power argues that transmission providers should perform "variance analyses" of all previously selected regional transmission facilities.²²³² LS Power contends that all variations in costs, from the initial regional planning estimate through project completion, should be maintained in a single publicly available database.²²³³

1038. Certain TDUs argue that the Commission should require each transmission provider, at the time it selects a transmission facility that is expected to be in service more than three years later, (1) to identify the key assumptions that drove its inclusion in the regional transmission plan and (2) to review triennially whether those key assumptions remain valid or have materially changed. To promote customer affordability by avoiding over-building or under-building transmission facilities, Certain TDUs contend that if these key assumptions have materially changed, the Commission should require transmission providers to evaluate whether any revisions are

necessary with respect to such transmission facilities.²²³⁴

1039. Large Public Power argues that, following selection of transmission facilities in Long-Term Regional Transmission Planning, the Commission should require transmission providers to create a cost and risk management framework. Specifically, Large Public Power argues that the Commission should require transmission providers to develop and implement protocols requiring the developer of a transmission facility to file periodic reports with the Commission tracking anticipated project costs against cost projections and updating benefits information. In the period before construction begins, if such reports indicate that anticipated costs have exceeded an identified threshold, or that benefit-cost ratios have declined by an identified percentage, Large Public Power states that stakeholders could consider remedial action and the transmission developer could present stakeholders with mitigation plans. Further, if stakeholders do not reach consensus on the developer's mitigation plan, Large Public Power argues that stakeholders could petition the Commission to disallow regional cost allocation for the transmission facility. Finally, under Large Public Power's proposal, if the Commission disallowed regional cost allocation, the transmission developer would be eligible for abandoned plant cost recovery in the absence of imprudence.²²³⁵

1040. Large Public Power argues that its proposal would provide more protection to consumers than did Order No. 1000. Large Public Power further contends that its proposal is similar to, but more expansive than, MISO's existing variance analysis process, and that it would work together with the Commission's proposal to allow transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles.²²³⁶ APPA agrees with Large Public Power's proposal and argues that all interested stakeholders should have the opportunity to participate in any

²²²⁹ Illinois Commission Initial Comments at 6.

²²³⁰ APPA Initial Comments at 22 (citing APPA ANOPR Initial Comments at 9–10; APPA ANOPR Reply Comments at 4; APPA, et al., Statement of Bryce Nielsen, Docket No. RM21–17–000, at 2 (filed Nov. 12, 2021)).

²²³¹ *Id.* at 35–36.

²²³² LS Power Supplemental Comments at 13–15.

²²³³ *Id.* at 13.

²²³⁴ Certain TDUs Initial Comments at 20.

²²³⁵ Large Public Power Initial Comments at 11–12.

²²³⁶ *Id.* (citing NOPR, 179 FERC ¶ 61,028 at P 248; Order No. 1000, 136 FERC ¶ 61,051 at PP 7, 263, 329; MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0)).

process to reassess previously approved transmission projects.²²³⁷

1041. New York Commission and NYSEERDA state that, while transmission providers can identify transmission needs using a 20-year transmission planning horizon, transmission facilities should be selected closer in time to when the need is anticipated to materialize. New York Commission and NYSEERDA state the final order should direct transmission providers to develop “off ramps” in Long-Term Regional Transmission Planning so that previously identified Long-Term Regional Transmission Facilities can be reevaluated as the facility’s needed-by date approaches. New York Commission and NYSEERDA state that conducting ongoing review can help reduce the risk of stranded costs.²²³⁸

1042. NRECA contends that selecting transmission projects 20 years in advance is not necessary or even workable. NRECA contends that under the Commission’s proposal, transmission providers would select Long-Term Regional Transmission Facilities conditionally and wait until a subsequent Long-Term Regional Transmission Planning cycle to confirm that selection decision, at which point the transmission developer would become eligible to use the applicable regional cost allocation method. NRECA argues that the Commission should allow a transmission provider during such a subsequent cycle to find that a previously selected transmission facility is no longer needed, either because the transmission need no longer exists or because the facility is no longer the most efficient or cost-effective solution to meet the need.²²³⁹

1043. ISO-NE takes no position on the Commission’s proposal but argues that the Commission should allow transmission providers the flexibility to determine the treatment of previously selected transmission projects based on outcomes of subsequent Long-Term Regional Transmission Planning cycles.²²⁴⁰

1044. A number of commenters oppose or express concerns with the Commission’s proposal to allow transmission providers to make the selection of a Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles. For example, AEP argues that, once

selected through Long-Term Regional Transmission Planning, transmission providers should include transmission facilities in future scenario analysis except where a new study raises serious doubt that the transmission facilities continue to provide net benefits. AEP contends that re-studying such transmission facilities will lead to an endless cycle of study and ultimately underinvestment in necessary transmission infrastructure, as well as increased costs for customers.²²⁴¹ Similarly, Indicated PJM TOs argue that, once selected, transmission facilities should remain in the regional transmission plan unless there is serious doubt a transmission facility would provide net benefits.²²⁴²

1045. Avangrid argues that there must be a high bar in subsequent Long-Term Regional Transmission Planning cycles for removing a previously selected transmission facility from the regional transmission plan because transmission developers must have confidence that selection in Long-Term Regional Transmission Planning represents a “definitive directive[] to invest capital.”²²⁴³ Avangrid states that transmission facilities should not be de-selected unless there are changed circumstances that would make continued development of the project materially detrimental. Avangrid argues that otherwise, Long-Term Regional Transmission Planning effectively will be an informational exercise on which investors cannot rely.²²⁴⁴

1046. Eversource recommends that the Commission clarify that once transmission facilities are selected in a Long-Term Regional Transmission Planning cycle, they will not be subject to reevaluation, because such reevaluation would undermine the transmission planning process and deter transmission investment that the Commission is seeking to encourage.²²⁴⁵ Similarly, Exelon argues that the Commission should clarify that the selection of transmission facilities identified in Long-Term Regional Transmission Planning should be a conclusive action that is reasonably final and on which transmission developers can rely. Exelon explains that Long-Term Regional Transmission Facilities are likely to be high-voltage backbone facilities that meaningfully impact power flows on the transmission system and argues that restudy or reconsideration should be the exception

and not the rule, allowing for their inclusion in system planning models used for other purposes (e.g., regional transmission planning addressing reliability and economic transmission needs and generator interconnection studies).²²⁴⁶

1047. WIRES contends that the Commission should clarify that transmission providers need not reevaluate previously selected Long-Term Regional Transmission Facilities after updating Long-Term Scenarios. WIRES claims that doing so would disrupt transmission facility development and raise costs.²²⁴⁷ Similarly, PPL argues that the Commission should exempt transmission facilities that are under construction or for which equipment has been purchased from any reevaluation in subsequent Long-Term Regional Transmission Planning cycles.²²⁴⁸ Invenery argues that while Long-Term Scenarios should be regularly reassessed and updated, these updates should apply only to future Long-Term Regional Transmission Planning cycles and should not result in re-assessment of previously selected transmission facilities.²²⁴⁹

c. Commission Determination

1048. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to include in their OATTs provisions that require them—in certain circumstances—to reevaluate Long-Term Regional Transmission Facilities that previously were selected. These OATT provisions must meet the requirements set forth below, as well as the minimum requirements for transmission providers’ broader evaluation process and selection criteria described above in the Minimum Requirements section.

1049. Specifically, we direct transmission providers to revise their OATTs to require reevaluation of any selected Long-Term Regional Transmission Facilities in the following three situations, subject to limitations that we set forth below: (1) delays in the development of a previously selected Long-Term Regional Transmission Facility would jeopardize a transmission provider’s ability to meet its reliability needs or reliability-related service obligations;²²⁵⁰ (2) the actual or

²²³⁷ APPA Reply Comments at 11–12 (citing Large Public Power Initial Comments at 11–12).

²²³⁸ New York Commission and NYSEERDA Initial Comments at 12.

²²³⁹ NRECA Initial Comments at 25–26 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

²²⁴⁰ ISO-NE Initial Comments at 36.

²²⁴¹ AEP Initial Comments at 13–14.

²²⁴² Indicated PJM TOs Initial Comments at 11.

²²⁴³ Avangrid Initial Comments at 11.

²²⁴⁴ *Id.*

²²⁴⁵ Eversource Initial Comments at 15–16.

²²⁴⁶ Exelon Initial Comments at 17–18.

²²⁴⁷ WIRES Initial Comments at 7.

²²⁴⁸ PPL Initial Comments at 6.

²²⁴⁹ Invenery Initial Comments at 4–5 (citing NOPR, 179 FERC ¶ 61,028 at app. B).

²²⁵⁰ We note that this is the same as the requirement adopted in Order No. 1000. See Order

projected costs of a previously selected Long-Term Regional Transmission Facility significantly exceed cost estimates used in the selection of a Long-Term Regional Transmission Facility; or (3) significant changes in Federal, federally-recognized Tribal, state, or local laws or regulations cause reasonable concern that a previously selected Long-Term Regional Transmission Facility may no longer meet the transmission providers' selection criteria.²²⁵¹

1050. In addition, we require transmission providers to include specific criteria in their OATTs that they will use to determine when one of these three situations occurs, thereby triggering the reevaluation of a previously selected Long-Term Regional Transmission Facility. For example, with respect to exceeding cost estimates (the second situation listed above), transmission providers may propose a specific threshold of cost escalation (e.g., a percent of total facility cost) above which the transmission providers would reevaluate a previously selected Long-Term Regional Transmission Facility. As another example, with respect to delays (the first situation listed above), transmission providers may propose specific development milestones that, if missed, may jeopardize the transmission developer's schedule and ultimately a transmission provider's ability to meet its reliability needs or reliability-related service obligations. We provide transmission providers with flexibility to propose these criteria on compliance, subject to the requirement that, as with the transmission providers' selection criteria, the reevaluation criteria must seek to maximize benefits accounting for costs over time without over-building transmission facilities. As such, in establishing such criteria, we expect transmission providers will balance the need to provide transmission developers with adequate investment certainty, absent which more efficient or cost-effective Long-Term Regional Transmission Facilities will not be developed, against the risk that, due to significant changes in circumstances, failing to reevaluate a selected Long-Term Regional Transmission Facility may result in the over-building of transmission. In addition, transmission providers must designate a point after which all selected Long-Term Regional Transmission Facilities will no longer

be subject to reevaluation, such that the transmission developer of the selected Long-Term Regional Transmission Facility has adequate certainty to make investment decisions, e.g., when the facility's transmission developer has secured all relevant permits and authorizations for the Long-Term Regional Transmission Facility.

1051. Further, as discussed further below, transmission providers may not reevaluate any selected Long-Term Regional Transmission Facility on the basis of significant changes in Federal, federally recognized-Tribal, state, or local laws or regulations unless, during the Long-Term Regional Transmission Planning cycle in which transmission providers selected the Long-Term Regional Transmission Facility, the Long-Term Regional Transmission Facility's targeted in-service date was in the latter half of the 20-year transmission planning horizon for Long-Term Regional Transmission Planning.

1052. We also require transmission providers to include in the reevaluation provisions in their OATTs the process and procedures that they will use to reevaluate a previously selected Long-Term Regional Transmission Facility, including the potential outcomes of reevaluation (e.g., taking no action, imposing a mitigation plan, reassigning the Long-Term Regional Transmission Facility to a different transmission developer, modifying the Long-Term Regional Transmission Facility, removing the Long-Term Regional Transmission Facility from the regional transmission plan).²²⁵² In particular, transmission providers must describe the conditions under which they would remove a previously selected Long-Term Regional Transmission Facility from the regional transmission plan.²²⁵³ We

²²⁵² See, e.g., MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0), § IX.E (setting forth potential outcomes of MISO's variance analysis procedures). Mitigation plans would provide to transmission developers the opportunity to address the cause of the reevaluation. For example, where reevaluation occurs because there are delays in the development of a previously selected Long-Term Regional Transmission Facility, transmission providers might require the transmission developer to develop an operating procedure to ensure that the transmission providers are able to address the reliability need or meet the reliability-related service obligation in the period before the Long-Term Regional Transmission Facility will be placed in service.

²²⁵³ We note that, in the event that the Long-Term Regional Transmission Facility was subject to competitive processes when it was selected, we do not require transmission providers to re-conduct these competitive processes in the event that the reevaluation process results in a change to the scope of the Long-Term Regional Transmission Facility. Instead, transmission providers have the flexibility to propose on compliance and explain whether, and if so when, they will re-run the

provide flexibility to transmission providers to propose such processes and procedures, subject to the following requirements. First, reevaluation on the basis of cost increases or significant changes in Federal, federally-recognized Tribal, state, or local laws or regulations must be part of a subsequent Long-Term Regional Transmission Planning cycle following selection and must take into account not only the updated costs but also the updated benefits of the Long-Term Regional Transmission Facility.²²⁵⁴ Second, in order to allow for reevaluation to occur, these processes and procedures must include mechanisms for tracking costs so that transmission providers have an accurate way to determine if the actual or projected costs of the previously selected Long-Term Regional Transmission Facility exceed cost estimates by the relevant threshold, therefore requiring transmission providers to reevaluate that Long-Term Regional Transmission Facility. Third, the reevaluation processes and procedures must seek to maximize benefits accounting for costs over time without over-building transmission facilities. Again, we expect transmission providers in establishing these processes and procedures, including potential mitigation measures, to consider outcomes that enable more efficient or cost-effective Long-Term Regional Transmission Facilities to be developed, while addressing the risk of over-building.

1053. We note that in setting forth these requirements, we have carefully reviewed the record developed here and weighed commenters' countervailing arguments. We believe that the reevaluation requirements set forth above strike a careful balance between two broad objectives of Long-Term Regional Transmission Planning. On the one hand, we believe that transmission providers must have the opportunity to select more efficient or cost-effective Long-Term Regional Transmission Facilities, which requires sufficiently long-term, forward-looking, and comprehensive regional transmission planning practices. Moreover, for selection to meaningfully result in the development of such more efficient or cost-effective Long-Term Regional

competitive transmission development process as part of the reevaluation process.

²²⁵⁴ Further, to perform the reevaluation analysis, we expect that transmission providers will use the updated Long-Term Scenarios and associated transmission system models that are developed for the Long-Term Regional Transmission Planning cycle in which the transmission provider reevaluates the selected Long-Term Regional Transmission Facility.

No. 1000, 136 FERC ¶ 61,051 at P 329; Order No. 1000-A, 139 FERC ¶ 61,132 at P 442; NOPR, 179 FERC ¶ 61,028 at P 247 & n.395.

²²⁵¹ NOPR, 179 FERC ¶ 61,028 at P 248.

Transmission Facilities, it must provide adequate certainty to transmission developers to support capital investment.

1054. On the other hand, we also acknowledge the inherent uncertainty involved in predicting future transmission needs, and the continued selection of Long-Term Regional Transmission Facilities that no longer meet the transmission providers' selection criteria closer to the time that those facilities are expected to go into service could be costly for consumers. Where transmission providers have selected Long-Term Regional Transmission Facilities further out in the transmission planning horizon, and where transmission providers timely obtain updated information about significant changes to the costs or benefits of such facilities, we believe that transmission providers must, consistent with the requirements in this final order, reevaluate a selected Long-Term Regional Transmission Facility in order to ensure that the facility continues to meet the transmission providers' selection criteria.

1055. In the NOPR, the Commission attempted to balance these objectives by proposing that, because the required development schedule of a previously selected Long-Term Regional Transmission Facility may not require its transmission developer to take actions or incur expenses in the near-term, transmission providers might be able to make the selection status of a previously selected Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles.²²⁵⁵ On further reflection, however, and after reviewing comments submitted in response to the NOPR,²²⁵⁶ we find that conditioning the selection of a Long-Term Regional Transmission Facility in this manner and on a routine basis may introduce too much uncertainty into transmission providers' evaluation and selection of Long-Term Regional Transmission Facilities.²²⁵⁷ We agree with AEP that routine reevaluation would require repeated

studies and ultimately could lead to underinvestment in Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs.²²⁵⁸ Therefore, we do not adopt the NOPR proposal to allow transmission providers to make the selection status of a previously selected Long-Term Regional Transmission Facility subject to the outcome of subsequent Long-Term Regional Transmission Planning cycles.

1056. Nevertheless, we continue to believe that transmission providers may be reticent to select—and Relevant State Entities and other stakeholders may not support the selection of—certain Long-Term Regional Transmission Facilities in the absence of a requirement for transmission providers to reevaluate the selection of such facilities should significant new information become available that could give rise to concerns that those facilities no longer meet the transmission providers' selection criteria.²²⁵⁹ Further, as is required for regional transmission planning processes under Order No. 1000, transmission providers also must have the ability to take action when delays in developing a Long-Term Regional Transmission Facility risk jeopardizing a transmission provider's ability to meet its reliability needs or reliability-related service obligations.²²⁶⁰

1057. As discussed above, selection of a Long-Term Regional Transmission Facility is only one step in the process of developing, constructing, and placing that facility in service for the benefit of customers. Given the risks involved in transmission development, it is necessary to provide sufficient certainty to transmission developers and their financing partners that reevaluation will not lead to endless studies and protracted dispute. Therefore, we require transmission providers to set forth in their OATTs a reevaluation process, as outlined above, that ensures that any reevaluation of Long-Term Regional Transmission Facilities that have been selected will occur only in the circumstances that we have described.

1058. We agree with APPA that reevaluation—and in particular any determination of whether a Long-Term

Transmission Need continues to exist or whether a Long-Term Regional Transmission Facility continues to meet the transmission providers' selection criteria—will require transmission providers to be able to track the costs of developing Long-Term Regional Transmission Facilities.²²⁶¹ We note above that transmission providers must propose on compliance the mechanism that they will use to track the costs of selected Long-Term Regional Transmission Facilities.

1059. As discussed above, however, we note that, when conducting a reevaluation of a selected Long-Term Regional Transmission Facility, transmission providers must update not only actual and projected costs but also their calculation of the benefits of the selected Long-Term Regional Transmission Facility. Such a requirement will ensure that transmission providers are comparing the relevant costs and benefits, *i.e.*, the updated costs and benefits of the selected Long-Term Regional Transmission Facility, to determine whether the Long-Term Regional Transmission Facility continues to be a more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs. Because updating the calculation of the benefits of a Long-Term Regional Transmission Facility is not as straightforward as tracking costs, we require reevaluation on the basis of cost escalations or of changes in Federal, federally-recognized Tribal, state, or local laws and regulations to occur as part of a subsequent Long-Term Regional Transmission Planning cycle. We find that this requirement is appropriate given the substantial time and resources that we expect will be necessary to update the underlying assumptions used in the transmission planning models, which must take place in order to update the calculation of the benefits of selected Long-Term Regional Transmission Facilities for purposes of such reevaluations. Requiring transmission providers to update these assumptions and their transmission planning models, including all Long-Term Scenarios and any associated sensitivities, beyond a subsequent Long-Term Regional Transmission Planning cycle would introduce unnecessary disruptions and potentially impede the efficient conduct of the next Long-Term Regional Transmission Planning cycle.

1060. In response to Kansas Commission, we decline to allow transmission providers to remove a Long-Term Regional Transmission Facility from a regional transmission

²²⁵⁵ NOPR, 179 FERC ¶ 61,028 at P 248.

²²⁵⁶ See, e.g., Exelon Initial Comments at 17–18 (arguing that selection should be “reasonably final” and that routine reevaluation would harm the certainty required for developing Long-Term Regional Transmission Facilities, inhibit efficient interconnection queue processing, and undermine system reliability as a whole).

²²⁵⁷ For this reason, we are unpersuaded by NRECA's argument that transmission providers should conditionally select Long-Term Regional Transmission Facilities subject to confirmation in a subsequent Long-Term Regional Transmission Planning cycle. NRECA Initial Comments at 25–26 (citing NOPR, 179 FERC ¶ 61,028 at P 248).

²²⁵⁸ See AEP Initial Comments at 13–14.

²²⁵⁹ See, e.g., APPA Initial Comments at 22 (arguing that there should be “off ramps” protecting transmission customers from Long-Term Regional Transmission Facilities that, following selection, are rendered unnecessary or inefficient by intervening changes (citations omitted)).

²²⁶⁰ Order No. 1000, 136 FERC ¶ 61,051 at P 329; Order No. 1000–A, 139 FERC ¶ 61,132 at P 442.

²²⁶¹ APPA Initial Comments at 36.

plan for purposes of cost allocation solely because other regional transmission planning processes do not establish a need for that transmission facility.²²⁶² Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes identify transmission needs differently, and we do not agree based on the requirements that we establish in this final order for Long-Term Regional Transmission Planning that reevaluation based solely on transmission needs identified through existing Order No. 1000 regional transmission planning processes is appropriate. We also decline Certain TDUs' request that the Commission require transmission providers to identify certain key assumptions driving the selection of Long-Term Regional Transmission Facilities and to review these assumptions in subsequent Long-Term Regional Transmission Planning cycles. Long-Term Regional Transmission Planning will necessitate that transmission providers compile a wide range of information from multiple data sources, analyze the effect of that information, develop Long-Term Scenarios that provide a view into what Long-Term Transmission Needs may be, and evaluate Long-Term Regional Transmission Facilities in light of these multiple different scenarios. In this light, we believe that Certain TDUs' suggested approach would not capture the complex interactions of the various factors giving rise to Long-Term Transmission Needs.

1061. Finally, we note that a coalition of diverse interests, including transmission developer, utility, and consumer interests, jointly expressed support for a framework that would provide for reconsideration of a Long-Term Regional Transmission Facility where cost and benefit projections deviate substantially from those at the time of selection.²²⁶³ We appreciate such efforts to bridge divergent interests to find common ground in a compromise proposal, and believe that the reevaluation requirements adopted here, like that widely supported compromise, strike a balance between competing interests.

F. Implementation of Long-Term Regional Transmission Planning

1. NOPR Proposal

1062. In the NOPR, the Commission proposed to require transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning efforts. The Commission stated that it recognized the possibility that there may be overlap in the time horizon for the proposed Long-Term Regional Transmission Planning and existing near-term regional transmission planning processes and that they will likely inform each other.²²⁶⁴ The Commission also stated that it is possible that, in some cases, transmission facilities selected to address transmission needs driven by changes in the resource mix and demand may provide near-term reliability or economic benefits, and thus potentially displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.

1063. In the NOPR, the Commission also sought comment on whether the Commission should host a periodic forum for transmission providers, transmission experts, relevant Federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning.²²⁶⁵

2. Comments

a. Comments on the Initial Timing Sequence

1064. Several commenters support requiring transmission providers to explain on compliance how Long-Term Regional Transmission Planning will interact with existing Order No. 1000 regional transmission planning processes.²²⁶⁶ Several commenters urge the Commission to allow regional flexibility with respect to coordination between existing Order No. 1000 regional transmission planning processes and Long-Term Regional Transmission Planning.²²⁶⁷ NESCOE argues that it could be counterproductive and unnecessary for

the Commission to dictate the initial timing of new processes to coordinate them with existing Order No. 1000 regional transmission planning processes.²²⁶⁸ PPL stresses the need for clarity on how the existing Order No. 1000 regional transmission planning processes interacts with Long-Term Regional Transmission Planning and states that each transmission planning region will need to address how planned reliability and economic projects should or should not be reflected in, evaluated against, and affected by long-term studies.²²⁶⁹

1065. R Street states that the NOPR correctly identifies challenges in harmonizing existing Order No. 1000 and Long-Term Regional Transmission Planning. R Street argues that the two processes should use different time frames and assumptions, with timing optimized to account for uncertainty. R Street maintains that existing Order No. 1000 transmission planning should be conducted annually over a transmission planning horizon of up to five years and should account for only those generators that are existing, under construction, or have interconnection agreements. R Street states that Long-Term Regional Transmission Planning should be conducted every two or three years over a 20-year transmission planning horizon and should account for representative generation development expectations and longer-term load growth. R Street posits that the long-term process should then feed into the near-term process, and transmission projects failing a cost-benefit test in one transmission planning cycle can roll over to the next in-kind cycle.²²⁷⁰

1066. PIOs contend that the different timing for Order No. 1000 transmission planning process cycles across transmission planning regions can create inconsistent assumptions, uncoordinated project identification between the two processes, confusion, and administrative burden.²²⁷¹ To address this concern, PIOs assert that the Commission should: (1) mandate Order No. 1000 regional transmission planning process cycles be no longer than Long-Term Regional Transmission Planning cycles and if shorter, divide Long-Term Regional Transmission Planning cycles evenly;²²⁷² (2) synchronize assumptions so that assumptions are identical for years

²²⁶² See Kansas Commission Initial Comments at 14.

²²⁶³ See *Advocates Advance Transmission Planning Cost Management Proposal At FERC*, Large Public Power Council (Mar. 6, 2024), <https://www.lppc.org/news/lppc-and-advocacy-groups-advance-transmission-planning-cost-management-proposal-at-ferc> (describing endorsements by LPPC, ACEG, CEBA, and NASUCA).

²²⁶⁴ NOPR, 179 FERC ¶ 61,028 at P 253.

²²⁶⁵ *Id.* P 255.

²²⁶⁶ Ameren Initial Comments at 22–23; APPA Initial Comments at 5, 24–25; Idaho Commission Initial Comments at 5; National Grid Initial Comments at 19; NYISO Initial Comments at 13.

²²⁶⁷ Ameren Initial Comments at 22–23; Duke Initial Comments at 29; NARUC Initial Comments at 33; National Grid Initial Comments at 19; NESCOE Initial Comments at 51–52; NYISO Initial Comments at 13; Pacific Northwest State Agencies Initial Comments at 20.

²²⁶⁸ NESCOE Initial Comments at 51–52.

²²⁶⁹ PPL Initial Comments at 4.

²²⁷⁰ R Street Initial Comments at 10–11.

²²⁷¹ PIOs Initial Comments at 47.

²²⁷² As an example, if a transmission provider uses a 36-month Long-Term Regional Transmission Planning cycle, its Order No. 1000 transmission planning cycles should be 36, 18, or 12 months. *Id.*

where both a Long-Term Regional Transmission Planning cycle and an existing Order No. 1000 regional transmission planning cycle start; (3) clarify the time period for existing Order No. 1000 regional transmission planning for economic and reliability needs; and (4) require transmission providers to clarify when results of one transmission planning process are incorporated into another, and require reasonable efforts to avoid one process disrupting the other.²²⁷³

b. Comments on Periodic Forums

1067. Several commenters support the Commission's proposal to host a periodic forum for transmission providers, transmission experts, relevant Federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning.²²⁷⁴ For example, AEP states that periodic forums would allow stakeholders to discuss best available data, modeling inputs, and techniques for calculating benefits.²²⁷⁵ GridLab states that a periodic forum, along with follow-on technical conferences and a periodic forum, could promote greater convergence in planning methods among transmission providers.²²⁷⁶

1068. Pacific Northwest State Agencies suggest that the Commission could hold technical conferences or regional sessions similar to the Federal State Task Force on Electric Transmission.²²⁷⁷ In contrast, PJM states that the periodic forum should be less formal than the technical conference format and that the Commission should consider using existing interconnection-wide organizations to host some of these forums.²²⁷⁸ SPP also notes that there are existing forums that could be leveraged, such as the Eastern Interconnection Planning Collaborative.²²⁷⁹

1069. Some commenters recommend that the forums be held on an annual or

a triennial schedule.²²⁸⁰ MISO notes that, while the current pace of change might warrant multiple technical discussions to understand emerging trends, over the long term such technical forums may only be necessary when new industry trends are identified.²²⁸¹ Nevada Commission and Northwest and Intermountain suggest that the forum could be structured into two parts, separated by policy and technical discussion, by RTOs/ISOs and OATT transmission planning regions, or by Eastern and Western Interconnection.²²⁸²

1070. Dominion and Idaho Power oppose the Commission hosting additional periodic forums.²²⁸³ Dominion recommends that the Commission use the existing Joint Federal-State Task Force on Electric Transmission instead.²²⁸⁴ Idaho Power asserts that the most useful approach would be to allow transmission planning regions the time necessary to formulate processes that meet the Commission's requirements, and additional time for implementation and integration of those processes into current transmission planning processes.²²⁸⁵

3. Commission Determination

a. Initial Timing Sequence Implementation

1071. We adopt the NOPR proposal to require transmission providers to explain on compliance how the initial timing sequence for Long-Term Regional Transmission Planning interacts with existing regional transmission planning processes. Transmission providers must provide in their explanations any information necessary to ensure that stakeholders understand this interaction, including at least the following two components. First, we find that transmission providers must address the possible interaction between the transmission planning cycle for Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes. As the Commission stated in the NOPR, we recognize the possibility that there may be overlap in the time horizon for Long-Term Regional Transmission Planning and existing

Order No. 1000 regional transmission planning processes and that these processes will likely inform each other. Second, we find that transmission providers must address the possible displacement of regional transmission facilities from the existing regional transmission planning processes. As the Commission noted in the NOPR, it is possible that, in some cases, Long-Term Regional Transmission Facilities selected to address Long-Term Transmission Needs may provide near-term reliability or economic benefits, and thus could displace regional transmission facilities that are under consideration as part of existing regional transmission planning processes.²²⁸⁶

1072. We find that transmission providers should have the flexibility to integrate the existing regional transmission planning processes with Long-Term Regional Transmission Planning in a manner that mitigates the potential for disruption of the existing regional transmission planning processes, and we note the agreement of some commenters on this point.²²⁸⁷ However, we are also concerned that too much flexibility for transmission providers with respect to the date by which they must begin the first Long-Term Regional Transmission Planning cycle could lead to unnecessary delay in realizing these beneficial reforms for customers. Thus, we require transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final order are due, on which they will commence the first Long-Term Regional Transmission Planning cycle. However, we understand that it will likely be useful to align in some manner the Long-Term Regional Transmission Planning cycle with existing transmission planning cycles. In some cases, such alignment may not be possible to do within this one-year deadline. Therefore, transmission providers in a transmission planning region may propose to start the first Long-Term Regional Transmission Planning cycle on a date later than one year from the initial compliance filing due date, only to the extent needed to

²²⁷³ *Id.* at 48–49.

²²⁷⁴ ACOE Initial Comments at 15; AEP Initial Comments 6, 31; Arizona Commission Initial Comments at 9; GridLab Initial Comments at 3, 5, 19–20; Idaho Commission Initial Comments at 5; NARUC Initial Comments at 34; NESCOE Initial Comments at 52; Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17; NYISO Initial Comments at 14; Pacific Northwest State Agencies Initial Comments at 20; PJM Initial Comments at 7, 77; R Street Initial Comments at 11; SDG&E Initial Comments at 4; SPP Initial Comments at 24; US DOE Initial Comments at 35–36.

²²⁷⁵ AEP Initial Comments at 31.

²²⁷⁶ GridLab Initial Comments at 5.

²²⁷⁷ Pacific Northwest State Agencies Initial Comments at 20.

²²⁷⁸ PJM Initial Comments at 77.

²²⁷⁹ SPP Initial Comments at 24.

²²⁸⁰ AEP Initial Comments at 31; Arizona Commission Initial Comments at 9; Nevada Commission Initial Comments at 12.

²²⁸¹ MISO Initial Comments at 57.

²²⁸² Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17.

²²⁸³ Dominion Initial Comments at 15–16; Idaho Power Initial Comments at 8–9.

²²⁸⁴ Dominion Initial Comments at 15–16.

²²⁸⁵ Idaho Power Initial Comments at 8–9.

²²⁸⁶ NOPR, 179 FERC ¶ 61,028 at P 253.

²²⁸⁷ Ameren Initial Comments at 22–23; Anbaric Initial Comments at 4–5, 22–27; CAISO Initial Comments at 2–3, 9, 17–20; Duke Initial Comments at 29; Indicated PJM TOs Initial Comments at 12; Large Public Power Initial Comments at 14–16; NARUC Initial Comments at 33; National Grid Initial Comments at 19; NESCOE Initial Comments at 51–52; NYISO Initial Comments at 13; PPL Initial Comments at 4; Pacific Northwest State Agencies Initial Comments at 20; Transmission Dependent Utilities Initial Comments at 4–5.

align transmission planning cycles. While we encourage transmission providers to align transmission planning cycles if useful, to ensure that there is no inappropriate delay to starting Long-Term Regional Transmission Planning, transmission providers in a transmission planning region that propose a commencement date of later than one year from the compliance due date must include adequate support explaining how the proposed date to begin the first Long-Term Regional Transmission Planning cycle is necessary and appropriately tailored for their transmission planning region.

1073. In addition, we recognize commenters' concerns regarding the coordination of Long-Term Regional Transmission Planning and the existing Order No. 1000 regional transmission planning processes, and we encourage transmission providers to address in their explanation how their proposed Long-Term Regional Transmission Planning would facilitate moving beyond piecemeal transmission expansion to address relatively near-term transmission needs and toward a more robust, well-planned transmission system.²²⁸⁸

1074. With respect to the argument by NESCOE that it would be counterproductive and unnecessary for the Commission to dictate the initial timing of new processes,²²⁸⁹ we disagree. We find that it is necessary to establish a requirement for transmission providers to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final order are due (subject to the limited exception described above), on which they will commence the first Long-Term Regional Transmission Planning Cycle, in order to guarantee that implementation will not be subject to unreasonable or unnecessary delay. With regard to the proposals made by PIOs and R Street,²²⁹⁰ we decline to adopt these proposals because we lack the record to assess the impacts that these more prescriptive proposed requirements would have on existing transmission planning processes, and whether these proposals would work effectively across the differing transmission planning processes in each transmission planning region.

b. Periodic Forums

1075. We believe that it will be beneficial for the Commission to host a periodic forum for transmission

providers, transmission experts, relevant Federal and state agencies, and other stakeholders to share best practices in implementing Long-Term Regional Transmission Planning, and note commenters' agreement on this point.²²⁹¹ Accordingly, the Commission will organize forums to share best practices in implementing Long-Term Regional Transmission Planning and provide notice and relevant details in advance of the forums.

IV. Coordination of Regional Transmission Planning and Generator Interconnection Processes

A. Need for Reform and Overall Reform

1. NOPR Proposal

1076. In the NOPR, the Commission proposed to require that transmission providers consider, as part of their Long-Term Regional Transmission Planning, regional transmission facilities that address certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been constructed due to the withdrawal of the underlying interconnection request(s).²²⁹²

1077. The Commission preliminarily found that this requirement will support the establishment of just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates by addressing a potential barrier to integrating new sources of generation that may otherwise continue to exist absent such requirement in the regional transmission planning process.²²⁹³ As the Commission explained in the NOPR, the interaction between regional transmission planning and cost allocation processes and the generator interconnection process is limited—the baseline regional transmission planning models generally only incorporate interconnection projects that have completed an interconnection facilities study and are therefore near the end of the generator interconnection process.²²⁹⁴ The Commission stated,

²²⁹¹ ACORE Initial Comments at 15; AEP Initial Comments at 6, 31; Arizona Commission Initial Comments at 9; GridLab Initial Comments at 3, 5, 19–20; Idaho Commission Initial Comments at 5; NARUC Initial Comments at 34; NESCOE Initial Comments at 52; Nevada Commission Initial Comments at 12; Northwest and Intermountain Initial Comments at 9, 17; NYISO Initial Comments at 14; Pacific Northwest State Agencies Initial Comments at 20; PJM Initial Comments at 7, 77; R Street Initial Comments at 11; SDG&E Initial Comments at 4; SPP Initial Comments at 24; US DOE Initial Comments at 35–36.

²²⁹² NOPR, 179 FERC ¶ 61,028 at P 166.

²²⁹³ *Id.* P 168.

²²⁹⁴ *Id.* P 155 (citing ANOPR, 176 FERC ¶ 61,024 at P 23).

however, that where transmission system needs are repeatedly identified through generator interconnection processes, more efficient or cost-effective transmission expansion could be achieved through regional transmission planning and cost allocation that allocates costs in a manner that is at least roughly commensurate with estimated benefits and eliminates a potential barrier to entry for new generation resources.²²⁹⁵

1078. Additionally, the Commission sought comment on how the proposed requirement to evaluate such facilities for selection should interact with existing regional transmission planning processes and Long-Term Regional Transmission Planning.²²⁹⁶

2. Comments

a. On the Overall Reform

1079. Multiple commenters express support for the general notion of coordinating the transmission planning and generator interconnection processes.²²⁹⁷ Other commenters explicitly support the coordination proposal laid out in the NOPR,²²⁹⁸ with some of these commenters arguing that the NOPR proposal does not go far enough (as described below).²²⁹⁹

1080. Other commenters offer more qualified support for the NOPR proposal. APPA and Exelon see value in the proposal but emphasize that any interconnection-related network upgrades that meet the specified criteria must independently satisfy any other applicable criteria for selection.²³⁰⁰ Similarly, NRECA requests that the Commission clarify that interconnection-related network upgrades associated with withdrawn interconnection requests will not receive preferential treatment in Long-Term Regional Transmission Planning.²³⁰¹ Clean Energy Associations and ENGIE support the proposal but argue that the Commission's concern could be more efficiently addressed

²²⁹⁵ *Id.* P 161.

²²⁹⁶ *Id.* P 174.

²²⁹⁷ ACEG Initial Comments at 51–53; Clean Energy Buyers Initial Comments at 19; DC and Maryland Office of People's Counsel Initial Comments at 16; Fervo Reply Comments at 1; Handy Law Initial Comments at 8–9; Interwest Initial Comments at 10–11; Invenergy Initial Comments at 2; Ohio Commission Federal Advocate Initial Comments at 8; PIOs Initial Comments at 72–73; R Street Initial Comments at 7–8.

²²⁹⁸ ACEG Initial Comments at 51–53; California Commission Initial Comments at 27; SDG&E Initial Comments at 3.

²²⁹⁹ Acadia Center and CLF Initial Comments at 25–26; ACORE Initial Comments at 13.

²³⁰⁰ APPA Initial Comments at 31; Exelon Initial Comments at 11–13.

²³⁰¹ NRECA Reply Comments at 10–11.

²²⁸⁸ See *supra* Need for Reform section.

²²⁸⁹ NESCOE Initial Comments at 51–52.

²²⁹⁰ PIOs Initial Comments at 44–48; R Street Initial Comments at 10–11.

with better regional transmission planning.²³⁰²

b. Requesting Additional Reform

1081. Some commenters suggest that the NOPR proposal does not go far enough to integrate the transmission planning and generator interconnection processes or to improve interconnection-related network upgrade cost allocation.²³⁰³ ACORE argues that more dramatic reforms are necessary.²³⁰⁴ Anbaric contends that a planning assessment should be conducted whenever an interconnection request triggers interconnection-related network upgrades on the larger transmission system beyond the interconnection substation and associated facilities.²³⁰⁵ ELCON states that Long-Term Regional Transmission Planning should be integrated with the generator interconnection queue.²³⁰⁶ It suggests that the Commission hold regular workshops to review best practices for coordinating the interconnection queue, current regional transmission planning, and Long-Term Regional Transmission Planning to reduce interconnection queue backlogs, leading to larger regional transmission projects that would both incorporate interconnection-related transmission needs and be eligible for competitive bidding.²³⁰⁷

1082. Similarly, Enel urges the Commission to consolidate the generator interconnection process into the regional transmission planning process to allow transmission providers to jointly assess the benefits, and allocate the costs, of transmission projects that benefit system loads and new generation.²³⁰⁸ Likewise, Shell suggests that the Commission integrate Long-Term Regional Transmission Planning and generator interconnection processes, requiring the use of the same benefits analysis under the same criteria, including reliability, economic, and public policy needs. Shell asserts

that this approach would: increase opportunities to reduce costs to produce power and deliver it to load, unlock economies of scale and scope, improve processing times for generator interconnection requests, address first mover and free-rider risk, and potentially increase states' willingness to participate in cost allocation.²³⁰⁹

1083. Acadia Center and CLF argue that the proposal does not fully address shortfalls with the current method for cost allocation associated with interconnection-related network upgrades.²³¹⁰ They also express concern that the NOPR proposal would address a limited subset of generator interconnection needs and call for additional changes to better allocate the costs of interconnection-related network upgrades (especially those related to offshore wind development) to regional beneficiaries.²³¹¹ Similarly, PIOs state the current cost allocation for interconnection-related network upgrades violates settled law that requires costs to be allocated both to cost causers and beneficiaries.²³¹² Relatedly, Invenery argues that the most significant factor influencing an interconnection customer's decision to leave the interconnection queue is typically the cost of assigned interconnection-related network upgrades.²³¹³

1084. Invenery also argues that interconnection-related network upgrades would remedy existing issues and should thus be addressed through the regional transmission planning process.²³¹⁴ Invenery asserts that some regions use different dispatch and other assumptions in the regional transmission planning and generator interconnection processes, which can result in persistent system overloads not being addressed through the regional transmission planning process.²³¹⁵ Similarly, Concerned Scientists aver that generator interconnection requests could be 10 years old when the NOPR proposal designates the related interconnection-related network upgrades as suitable for consideration in future Long-Term Scenarios.²³¹⁶ Concerned Scientists argue that the Commission should require the inclusion in Long-Term Scenarios of interconnection-related transmission

needs that the generator interconnection process identified multiple times.²³¹⁷

c. Concerns With the Overall Reform

1085. Some commenters oppose the Commission's proposal.²³¹⁸ AEP, Ameren, CAISO, and Utah Division of Public Utilities argue that the proposal is unnecessary.²³¹⁹ Duke argues that the Commission's proposal is unnecessarily prescriptive, difficult to implement, and risks introducing significant subjectivity and complex administration into the transmission planning process.²³²⁰ Ameren claims the proposal will result in inefficient regional transmission planning because it will not minimize total cost to end-use customers.²³²¹

1086. Vistra argues that the NOPR proposal does not address how the newly created interconnection capacity will be allocated and how the timing and implementation of such upgrades would work.²³²²

1087. MISO contends that the Commission should not adopt prescriptive rules for integrating the generator interconnection and regional transmission planning processes, but instead continue to allow the RTOs/ISOs to develop those processes that best fit their footprint.²³²³ MISO argues that expanding the generator interconnection process beyond its current five-year outlook would slow the generator interconnection process.²³²⁴ MISO requests that if the Commission does not eliminate the NOPR proposal, as MISO would prefer, then the requirement should be altered so that transmission providers would only be required to post a list of generator interconnection upgrades that met the defined criteria.²³²⁵

1088. CAISO disagrees with California Commission's comments that the NOPR proposal could improve CAISO's existing interconnection-related network upgrade provisions because the two processes have significantly different eligibility requirements,

²³⁰² Clean Energy Associations Initial Comments at 15; ENGIE Initial Comments at 5.

²³⁰³ Anbaric Initial Comments at 7–9; Clean Energy Associations Initial Comments at 25–26; Concerned Scientists Initial Comments at 21–22; ELCON Initial Comments at 13–14; Enel Initial Comments at 4–5; Invenery Initial Comments at 10–13; Invenery Reply Comments at 12–13; PIOs Initial Comments at 72–73; Shell Reply Comments at 3–7.

²³⁰⁴ ACORE Initial Comments at 13.

²³⁰⁵ Anbaric Initial Comments at 7–8.

²³⁰⁶ ELCON Initial Comments at 13–14.

²³⁰⁷ *Id.* at 14–15.

²³⁰⁸ Enel Initial Comments at 4–5 (citing Enel, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*, <https://www.enelgreenpower.com/content/dam/enel-egp/documenti/share/working-paper.pdf> (last visited Apr. 2024)).

²³⁰⁹ Shell Reply Comments at 3, 5, 6–7.

²³¹⁰ Acadia Center and CLF Initial Comments at 25–26.

²³¹¹ *Id.* at 25.

²³¹² PIOs Initial Comments at 72.

²³¹³ Invenery Reply Comments at 14.

²³¹⁴ *Id.* at 12.

²³¹⁵ *Id.*

²³¹⁶ Concerned Scientists Reply Comments at 22.

²³¹⁷ *Id.*

²³¹⁸ AEP Initial Comments at 6, 18; Ameren Initial Comments at 17; CAISO Initial Comments at 34; Duke Initial Comments at 4; Illinois Commission Initial Comments at 8–9; MISO Initial Comments at 44–47; PJM Initial Comments at 7, 85–86; PPL Initial Comments at 12.

²³¹⁹ AEP Initial Comments at 18–20; Ameren Initial Comments at 18; CAISO Initial Comments at 6, 34–35; Utah Division of Public Utilities Initial Comments at 7.

²³²⁰ Duke Initial Comments at 4, 20.

²³²¹ Ameren Initial Comments at 18.

²³²² Vistra Initial Comments at 33–34.

²³²³ MISO Initial Comments at 44; MISO Reply Comments at 28.

²³²⁴ MISO Reply Comments at 29.

²³²⁵ MISO Initial Comments at 45.

purposes, and impacts.²³²⁶ CAISO further argues that the NOPR proposal could require transmission planners to study only outdated interconnection-related network upgrades.²³²⁷

1089. Mississippi Commission states that interconnection-related network upgrades should focus on reducing costs and providing price signals and not be included in Long-Term Regional Transmission Planning.²³²⁸

1090. Some commenters argue that it is incorrect to assume that interconnection customers withdraw from the interconnection queue due solely to high interconnection-related network upgrade costs instead of other reasons²³²⁹ such as the project being uneconomic,²³³⁰ the project having insufficient site control or permitting delays,²³³¹ the project being speculative,²³³² or some other regulatory or economic factor.²³³³

1091. PJM recommends an alternative proposal for funding generation interconnections in which states play the major role.²³³⁴ Under the PJM proposal, states that want to incent generation interconnections, perhaps to support a renewable portfolio standard, could fund a backbone transmission system to help facilitate these interconnections.²³³⁵

1092. Invenergy asks the Commission not to consider certain alternative proposals advanced by other commenters.²³³⁶

d. Cost Allocation

1093. Some commenters oppose the NOPR proposal on the assumption that it could shift the cost for interconnection-related network upgrades from interconnection customers to load.²³³⁷ In addition, PJM

states that the Commission's proposal could lead to undue discrimination and would distort the price signal that generator developers should see to make reasonable investment decisions.²³³⁸

Industrial Customers state that generators should be able to recover the costs of interconnection through market revenues if their projects are competitive.²³³⁹ Industrial Customers further argue that under the cost causation principle, a new generator should pay for interconnection-related network upgrades if such upgrades are only required because of the generator's interconnection.²³⁴⁰ Vistra asserts that, although the proposal shifts costs indirectly, the Commission still must rationally explain its decision to depart from the existing just and reasonable "but-for" policy of Order No. 2003.²³⁴¹

1094. Other commenters oppose the Commission's proposed reform because it will increase the cost to serve load. AEP asserts that such a proposal would possibly result in the development of unnecessary transmission infrastructure, which would lead to increased transmission customer costs for no benefit.²³⁴² Dominion argues that this proposal could result in over-building and excessive rates for transmission customers.²³⁴³ TAPS asks the Commission to clarify that consideration of interconnection-related transmission needs would not foreclose transmission providers from proposing a cost allocation method that is different from the cost allocation for other types of Long-Term Regional Transmission Facilities.²³⁴⁴

e. Interconnection Queue Gaming Considerations

1095. Several commenters express concerns that the NOPR proposal would incentivize gaming by interconnection customers to promote development of interconnection-related network upgrades through the regional transmission planning process.²³⁴⁵ Some commenters claim that the

Commission's proposal could create a perverse incentive for interconnection customers to submit and withdraw multiple interconnection requests so that interconnection-related network upgrades can be considered for regional cost allocation,²³⁴⁶ especially in transmission planning regions with lower thresholds for entering and maintaining a position in the interconnection queue.²³⁴⁷

1096. Pennsylvania Commission, Shell, Eversource, and US DOE recommend the Commission modify the NOPR proposal to limit or prevent gaming. Pennsylvania Commission argues that adding more commitments on the part of the interconnection customer or requiring a more thorough analysis of the reasons for withdrawal is an appropriate way of addressing the concern.²³⁴⁸ Shell states that, to prevent gaming, the Commission should revise its proposal so that an upgrade is only eligible for inclusion in the Long-Term Regional Transmission Plan if it appears in one generator interconnection study cycle over a five-year period.²³⁴⁹ Eversource asks the Commission to find that submitting and withdrawing interconnection requests simply so that the required interconnection-related network upgrades would be identified twice in the operative period, for example, would violate the Commission's regulations, including but not limited to the duty of candor and the prohibition of market manipulation.²³⁵⁰ US DOE states that the Commission should strive to ensure that the reforms do not create the potential for gaming by generators, which, absent mitigation, could increase delays and backlogs in the interconnection queue.²³⁵¹

1097. In response, Interwest argues that suggestions that increased coordination would result in gaming assumes that developers know in advance what interconnection-related network upgrades they will be assigned through the interconnection process.²³⁵² Interwest argues that, given the uncertainty about whether, and when, such a process could apply and result in selection and construction of facilities under Long-Term Regional

²³²⁶ CAISO Reply Comments at 28–29 (citing California Commission Initial Comments at 27).

²³²⁷ *Id.* at 32.

²³²⁸ Mississippi Commission Reply Comments at 9.

²³²⁹ CAISO Reply Comments at 29; NRECA Reply Comments at 9; PJM Initial Comments at 87.

²³³⁰ American Municipal Power Initial Comments at 33–34; Indicated PJM TOs Initial Comments at 13–14; Pennsylvania Commission Initial Comments at 8; Vistra Initial Comments at 20.

²³³¹ Duke Initial Comments at 20–21; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 8; PJM Initial Comments at 88–89.

²³³² Entergy Initial Comments at 25.

²³³³ PJM Initial Comments at 89.

²³³⁴ *Id.* at 89–90.

²³³⁵ *Id.* at 90.

²³³⁶ Invenergy Reply Comments at 15 (citing MISO Initial Comments at 45; PJM Initial Comments 85, 90–92).

²³³⁷ APPA Initial Comments at 31; Industrial Customers Initial Comments at 13; NRECA Initial Comments at 41–42 (citation omitted); NRECA Reply Comments at 8–9; PJM Initial Comments at 89–90; Vistra Initial Comments at 8; Xcel Initial Comments at 15.

²³³⁸ PJM Initial Comments at 89.

²³³⁹ Industrial Customers Initial Comments at 13–14.

²³⁴⁰ *Id.* at 21–22.

²³⁴¹ Vistra Initial Comments at 9 (citation omitted).

²³⁴² AEP Initial Comments at 20.

²³⁴³ Dominion Initial Comments at 32.

²³⁴⁴ TAPS Initial Comments at 13–14.

²³⁴⁵ Ameren Initial Comments at 18–19; American Municipal Power Initial Comments at 34; Dominion Initial Comments at 32; Dominion Reply Comments at 7–8; EEI Initial Comments at 18; Eversource Initial Comments at 23–24; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 89; PPL Initial Comments at 12–13; Shell Initial Comments at 29–30; SPP Initial Comments at 16; Xcel Initial Comments at 16.

²³⁴⁶ Ameren Initial Comments at 18; American Municipal Power Initial Comments at 33–34; EEI Initial Comments at 18; Idaho Power Initial Comments at 6; PJM Initial Comments at 89.

²³⁴⁷ EEI Initial Comments at 18.

²³⁴⁸ Pennsylvania Commission Initial Comments at 9.

²³⁴⁹ Shell Initial Comments at 30.

²³⁵⁰ Eversource Initial Comments at 23–24 (citing 18 CFR 35.41; 18 CFR 1c.2).

²³⁵¹ US DOE Initial Comments at 27–28.

²³⁵² Interwest Reply Comments at 5–6 (citing EEI Initial Comments at 18).

Transmission Planning, it would not incentivize gaming.²³⁵³ Similarly, Invenery argues that developers would have no reasonable expectation that any interconnection-related network upgrade meeting the NOPR criteria ultimately would be selected through the multi-year regional transmission planning process and actually constructed on a timeline that accommodates the developer's generation facility.²³⁵⁴ If the Commission is concerned about possible gaming, however, Invenery urges the Commission to revise the proposal to require that withdrawn interconnection requests must have been submitted by unaffiliated entities.²³⁵⁵

f. Miscellaneous

1098. SEIA asks the Commission to clarify that the phrase "interconnection-related transmission needs" would allow transmission providers to include either individual or aggregated transmission solutions that address specific needs.²³⁵⁶ SEIA asks the Commission to require transmission providers to assume that these interconnection-related network upgrades will be built and include the interconnection-related network upgrades in their Long-Term Regional Transmission Planning.²³⁵⁷

1099. Several commenters argue that the reforms issued under Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements, will address interconnection-related issues more appropriately than the NOPR proposal.²³⁵⁸ Some commenters argue that the Commission should defer consideration of the NOPR proposal until the reforms issued under Order No. 2023 are implemented.²³⁵⁹

3. Need for Reform

1100. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission's existing regional transmission planning requirements are unjust, unreasonable, and unduly discriminatory or preferential because

they do not adequately consider certain interconnection-related transmission needs that the transmission provider has identified multiple times in the generator interconnection process but that have never been resolved due to the withdrawal of the underlying interconnection request(s). We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that there is insufficient coordination between the Commission's existing generator interconnection processes and regional transmission planning and cost allocation processes regarding interconnection-related transmission needs that are repeatedly identified in the generator interconnection process. As a result of this deficiency, transmission providers do not currently consider those identified interconnection-related transmission needs in their regional transmission planning processes, nor do they evaluate whether more efficient or cost-effective regional transmission solutions to these needs could be achieved through regional transmission planning processes and cost allocation. Accordingly, we find that existing regional transmission planning and cost allocation processes are insufficient to ensure just and reasonable rates, and we direct the reforms discussed below to address this deficiency.

1101. As explained in the NOPR,²³⁶⁰ we are concerned about the prevalence of interconnection-related network upgrades being repeatedly identified in the generator interconnection process in multiple interconnection queue cycles during a short period of time (e.g., five years) but not being developed because the interconnection request(s) driving the need for the upgrade are withdrawn. The record indicates that the level of spending on interconnection-related network upgrades has dramatically increased in recent years, escalating the cost of interconnecting new generation to the transmission system.²³⁶¹ The evidence also suggests that this trend is leading to more and more interconnection customers withdrawing

their interconnection requests in the face of significant costs associated with interconnection-related network upgrades.²³⁶² For example, between January 2016 and July 2020, 245 generation projects in advanced stages in the MISO generator interconnection process withdrew from the queue, with the project developers citing high interconnection-related network upgrade costs as the primary reason for their withdrawal.²³⁶³ While interconnection customers may choose to withdraw from the interconnection queue for a number of reasons, in recent years, the deciding factor has increasingly become the interconnection customer's "sticker shock" at its cost responsibility for interconnection-related network upgrades.²³⁶⁴

1102. When interconnection customers withdraw from the interconnection queue, the identified interconnection-related network upgrades associated with those interconnection customers remain unbuilt and the underlying interconnection-related transmission needs go unaddressed. In many cases, when the interconnection-related transmission need is not addressed via development of interconnection-related network upgrades in one interconnection queue cycle, the same interconnection-related transmission need—and oftentimes the same or a substantially similar interconnection-related network upgrade—will appear in subsequent interconnection queue cycles. One study, which analyzed 12 specific interconnection-related network upgrades identified by MISO and SPP, found that SPP identified three of the upgrades in two interconnection queue cycles and one in three interconnection queue cycles, and MISO identified three of the upgrades in two interconnection queue cycles and two in three interconnection queue cycles.²³⁶⁵ In other words, both SPP and MISO were repeatedly identifying the same interconnection-related network upgrades as interconnection customers withdrew from the interconnection queue, leaving later-in-time interconnection customers to address

²³⁵³ *Id.* at 6.

²³⁵⁴ Invenery Reply Comments at 14.

²³⁵⁵ *Id.* at 14–15.

²³⁵⁶ SEIA Initial Comments at 14 (citing SPP, 2020 Integrated Transmission Planning Assessment Report, at 87 (Oct. 27, 2020)).

²³⁵⁷ *Id.*

²³⁵⁸ Dominion Reply Comments at 8; Idaho Power Initial Comments at 6–7; Illinois Commission Initial Comments at 9; Pacific Northwest Utilities Initial Comments at 15.

²³⁵⁹ Duke Initial Comments at 20; EEI Initial Comments at 18; Entergy Initial Comments at 24–25.

²³⁶⁰ NOPR, 179 FERC ¶ 61,028 at PP 161–165.

²³⁶¹ See ICF Resources, LLC, *Just and Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits*, 2 (Sept. 9, 2021), <https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf> (ICF Sept. 2021 Interconnection Report); Jay Caspary et al., ACEG, *Disconnected: The Need for a New Generator Interconnection Policy*, 14 (2021), <https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf> (ACEG 2021 Interconnection Report).

²³⁶² ACEG 2021 Interconnection Report at 17.

²³⁶³ *Id.* (naming the high cost of interconnection-related network upgrades as the fundamental problem that interconnection queue reform has failed to address thus far).

²³⁶⁴ See ACOE ANOPR Comments at 12; DC and Maryland Office of People's Counsel Initial Comments at 16; Invenery Reply Comments at 14; Northwest and Intermountain Initial Comments at 14; see also Order No. 2023, 184 FERC ¶ 61,054 at P 41; Order No. 2023–A, 186 FERC ¶ 61,199 at P 14.

²³⁶⁵ ICF Sept. 2021 Interconnection Report at 25–26.

the same interconnection-related transmission needs.

1103. Where interconnection-related transmission needs are repeatedly identified in interconnection studies, the implication may be that the area, despite the potentially prohibitive interconnection costs if borne by one or a small number of interconnection customers, is otherwise desirable for generators to locate (e.g., it is located close to fuel sources). This repeated interest in accessing the transmission system, combined with the lack of available transmission capacity and prohibitive costs of interconnection-related network upgrades, together create a barrier to accessing the transmission system and establish a known interconnection-related transmission need. We find that this barrier to entry can hinder the timely development of new generation, thereby stifling competition in wholesale electricity markets and limiting access to lower-cost generation.²³⁶⁶ We find that existing regional transmission planning processes do not adequately consider or account for this specific set of interconnection-related transmission needs that go unaddressed in the generator interconnection processes. By failing to consider such interconnection-related transmission needs, the regional transmission planning process is unable to identify the more efficient or cost-effective regional transmission solutions.

1104. Moreover, the Commission has long recognized that interconnection-related network upgrades provide transmission benefits that extend beyond the interconnection customer.²³⁶⁷ By upgrading the transmission system in a piecemeal fashion through the generator interconnection process, as described

above, the current regional transmission planning paradigm can impose costs on interconnection customers for transmission facilities that provide benefits beyond those received by the interconnection customer. This paradigm allocates transmission costs in a way that may not be roughly commensurate with the distribution of benefits, a result that can lead to unjust and unreasonable rates. The reform adopted below requires the consideration of regional transmission facilities to meet interconnection-related transmission needs repeatedly identified in the generator interconnection process in the Order No. 1000 regional transmission planning and cost allocation processes, which we believe will result in more efficient or cost-effective regional transmission expansion, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which can enhance competition in wholesale electricity markets and facilitate access to lower-cost generation). In turn, we expect that these reforms will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

1105. Additionally, as discussed further below, we disagree with commenters that question the necessity of this reform. In addition to our findings that this reform will help ensure just and reasonable rates, we find that the specific purpose of this reform—to require transmission providers to evaluate certain interconnection-related transmission needs—is not a requirement of any existing process. Additionally, we find that the qualifying criteria established by this reform will ensure that the reform avoids placing an onerous burden on transmission providers. Finally, we disagree that this reform is overly prescriptive; it does not dictate a specific result or require that transmission providers select a regional transmission facility to address identified interconnection-related transmission needs. This reform merely requires consideration of these interconnection-related transmission needs in the regional transmission planning process.

4. Commission Determination

1106. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning processes in their OATTs, consistent

with the requirements in this final order, to evaluate for selection regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process, as more fully described below. We find that this requirement will ensure that more efficient or cost-effective transmission expansion can be effectuated through regional transmission planning processes and will eliminate a potential barrier to entry for new generation resources, thereby enhancing competition in wholesale electricity markets and facilitating access to lower-cost generation. As a result, this reform will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

1107. In this final order, we adopt the NOPR proposal with modification. First, we require transmission providers to evaluate for selection regional transmission facilities to address certain identified interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes, rather than in Long-Term Regional Transmission Planning. Second, we modify the NOPR proposal to require that an interconnection-related network upgrade associated with identified interconnection-related transmission needs must satisfy *both* the minimum cost and voltage criteria proposed in the NOPR to qualify for evaluation for selection.

1108. In recent years, spending on interconnection-related network upgrades has increased dramatically, and the high cost of interconnection is increasing the rate at which generators withdraw from the interconnection queue.²³⁶⁸ While interconnection customers may withdraw for multiple reasons, the record in this proceeding shows that, in recent years, the deciding factor in many cases of withdrawal has become the interconnection customer's cost responsibility for expensive interconnection-related network upgrades.²³⁶⁹ Consequently, interconnection customers are unlikely to resolve these interconnection-related transmission needs through the generator interconnection process.

1109. Where interconnection-related transmission needs are repeatedly

²³⁶⁶ The Commission has previously found that policies eliminating barriers to entry for generation resources can enhance competition in bulk power markets. *Standardization of Generator Interconnection Agreements & Procs.*, Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at PP 694 (2003), *order on reh'g*, Order No. 2003–A, 69 FR 15932 (Mar. 26, 2004), 106 FERC ¶ 61,220 at P 579, *order on reh'g*, Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003–C, 70 FR 37661 (June 30, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); Order No. 2023, 184 FERC ¶ 61,054 at P 44. Limited access to new and more competitive supplies of generation can increase the energy rates paid by wholesale customers. Order No. 2023, 184 FERC ¶ 61,054 at P 43.

²³⁶⁷ See, e.g., Order No. 2003, 104 FERC ¶ 61,103 at P 65 (stating that “[f]acilities beyond the Point of Interconnection [(i.e., interconnection-related network upgrades)] are part of the Transmission Provider's Transmission System and benefit all users”).

²³⁶⁸ ACEG 2021 Interconnection Report at 17.

²³⁶⁹ NOPR, 179 FERC ¶ 61,028 at P 162; DC and Maryland Office of People's Counsel Initial Comments at 16; Invenergy Reply Comments at 14; Northwest and Intermountain Initial Comments at 14.

identified but not constructed, the implication is that, despite the potentially prohibitive interconnection costs if borne by one or a small number of interconnection customers, there are compelling reasons, such as proximity to fuel sources, why generators seek to locate a point of interconnection at a specific location or locations associated with transmission constraints. When interconnection customers that have invested time and resources in engaging in the generator interconnection process choose to withdraw rather than fund interconnection-related network upgrades, it becomes increasingly apparent that interconnection customer(s) are unlikely to resolve interconnection-related transmission needs through the generator interconnection process.

1110. At the same time, the Commission has found, and courts have affirmed, that interconnection-related network upgrades identified in the generator interconnection process can provide widespread transmission benefits that extend beyond the interconnection customer.²³⁷⁰ As a result, planning these types of upgrades to the transmission system in a piecemeal fashion, exclusively through the generator interconnection process, limits the development of transmission facilities that would provide benefits to the transmission system beyond those received by the interconnection customer. This is the case where interconnection-related network upgrades of substantial cost are repeatedly identified to address interconnection-related transmission needs, but those needs continue to go unresolved through the generator interconnection process. In such cases, it may be more efficient or cost-effective to address such needs through the regional transmission planning and cost allocation process. Therefore, reforms are necessary to require interconnection-related transmission needs associated with interconnection-related network upgrades that are repeatedly identified in the generator interconnection process to be evaluated

through the regional transmission planning and cost allocation process. We believe that this approach will result in selection of more efficient or cost-effective regional transmission solutions that will provide benefits to the transmission system, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which will enhance competition in wholesale electricity markets and facilitate access to lower-cost generation).²³⁷¹ As a result, these reforms will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates.

1111. While we require transmission providers to evaluate regional transmission facilities that address certain interconnection-related transmission needs identified by this reform in the existing Order No. 1000 regional transmission planning and cost allocation processes, we allow for flexibility in how transmission providers evaluate such facilities for selection. Transmission providers may adopt the evaluation method and selection criteria from any of their existing Order No. 1000 regional transmission planning and cost allocation processes (e.g., economic or reliability processes) to evaluate and potentially select these types of transmission facilities. By not requiring a specific process, we permit transmission providers to propose the best method to incorporate this requirement within their existing regional transmission planning processes. We also encourage transmission providers to consider, as part of the evaluation process, whether regional transmission facilities that address certain identified interconnection-related transmission needs may also address other regional transmission needs more efficiently or cost-effectively.

1112. Several commenters suggest alternative reforms to coordinate or consolidate regional transmission planning and generator interconnection processes or to modify existing cost

allocation criteria.²³⁷² We find these requests to be outside the scope of this proceeding and lacking in record support to adequately consider whether to adopt them in this final order. In this final order, we are addressing the narrow issue of interconnection-related transmission needs being repeatedly identified yet continuing to go unresolved through the generator interconnection process, even though it may be more efficient and cost-effective to evaluate such needs through the regional transmission planning and cost allocation process.

1113. We find unconvincing general arguments from commenters that oppose the Commission's proposal because the reform addresses a deficiency in existing regional transmission planning and cost allocation processes, will ensure just and reasonable and not unduly discriminatory or preferential Commission-jurisdictional rates, is not unduly burdensome, and does not dictate a particular outcome. The level of prescriptiveness of this reform strikes the right balance between an open-ended requirement, which might not address the need for reform, and a very prescriptive requirement that could be overly burdensome to transmission providers.

1114. We are unpersuaded by Ameren's argument that this reform will result in inefficient regional transmission planning because it will not minimize the total cost to end-use customers.²³⁷³ As explained above, this reform will enable transmission providers to identify through regional transmission planning the more efficient or cost-effective transmission solution to address an interconnection-related transmission need.

1115. We clarify in response to Vistra that transmission providers must make the newly created interconnection capacity equally available to all interconnection and transmission customers consistent with the Commission's open access policy.²³⁷⁴ Any interconnection customers whose interconnection requests related to the initial identification of the interconnection-related transmission need would not have any priority rights to that newly created interconnection or transmission capacity. Additionally, we clarify, in response to NRECA's request, that we are not requiring interconnection-related network upgrades associated with withdrawn interconnection requests to be given

²³⁷⁰ See, e.g., *Entergy Svs., Inc. v. FERC*, 391 F.3d 1240, 1247–48 (2004); Order No. 2003, 104 FERC ¶ 61,103 at P 65 (stating that “[f]acilities beyond the Point of Interconnection [(i.e., interconnection-related network upgrades)] are part of the Transmission Provider's Transmission System and benefit all users”); see also ACOE ANOPR Comments, Ex. 5 at 4–7; CAISO ANOPR Comments at 53–54 (stating that in CAISO “transmission facilities at 200 kV and above are eligible for regional cost allocation,” including location-constrained resources interconnection facilities, because “this voltage threshold . . . recognizes that high voltage transmission facilities support and provide benefits to all customers to the CAISO grid”).

²³⁷¹ While in this portion of the final order we discuss the requirement that transmission providers evaluate in their existing regional transmission planning and cost allocation processes regional transmission facilities that address certain interconnection-related needs, we also expect that many of the other reforms in this final order regarding Long-Term Regional Transmission Planning will address the difficulties generators face in interconnecting to the transmission system and the cost allocation mismatch described here, including required Factor Category Six, interconnection requests and withdrawals.

²³⁷² E.g., Enel Initial Comments at 4–5.

²³⁷³ Ameren Initial Comments at 18.

²³⁷⁴ Vistra Initial Comments at 33–34.

preferential treatment in regional transmission planning.²³⁷⁵

1116. In response to commenters arguing that it is incorrect to assume that interconnection customers withdraw from the interconnection queue due solely to high interconnection-related network upgrade costs,²³⁷⁶ we explain that we are not requiring transmission providers to evaluate regional transmission facilities that address interconnection-related transmission needs for every withdrawn interconnection request. Instead, this reform is focused only on certain interconnection-related transmission needs that meet the specific qualifying criteria detailed below. We do not assume that where these criteria are met, the relevant interconnection customers have necessarily withdrawn from the interconnection queue solely due to high interconnection-related network upgrade costs. Rather, we determine that these criteria only suggest that high costs were *likely* a factor prompting, or at least contributing to, the relevant withdrawals. We conclude that where the criteria are met, there may be an opportunity for a more efficient or cost-effective regional transmission solution, such that an evaluation of the relevant interconnection-related transmission need(s) is appropriate.

1117. We are not persuaded to reject this reform based on commenters' assertions that this reform will shift the costs of interconnection-related network upgrades from interconnection customers to load.²³⁷⁷ This final order requires transmission providers to evaluate in their existing Order No. 1000 regional transmission planning and cost allocation processes regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process. Transmission providers will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution as part of the regional transmission planning process in order for any regional cost allocation method

to apply, and this final order does not alter the existing cost allocation methods in either the generator interconnection or existing Order No. 1000 regional transmission planning process. If a regional transmission facility that addresses identified interconnection-related transmission needs is not selected as part of the regional transmission planning process, then the associated regional cost allocation method would not apply; however, if the facility is selected, then the regional transmission planning process has determined that the regional transmission facility is a more efficient or cost-effective regional transmission solution. Additionally, if such a facility is selected, the Commission-approved *ex ante* regional cost allocation method for that facility would allocate its costs at least roughly commensurate with its estimated benefits.

1118. In response to TAPS' request that the Commission clarify that regions may propose differing cost allocation methods for transmission facilities selected to address interconnection-related transmission needs versus transmission facilities selected to address other types of transmission needs,²³⁷⁸ we clarify that the requirements adopted here merely create an obligation for transmission providers to evaluate regional transmission facilities that address certain identified interconnection-related transmission needs in the existing regional transmission planning and cost allocation processes. As such, to the extent that transmission providers wish to propose further changes to their Order No. 1000 regional transmission planning cost allocation method(s) because of this requirement, they would need to do so in separate FPA section 205 filings rather than on compliance with this final order.

1119. We disagree with commenters that the requirements adopted herein will incentivize gaming by interconnection customers to include interconnection-related network upgrades in the regional transmission planning process.²³⁷⁹ We also disagree with commenters that claim that interconnection customers will submit

spurious interconnection requests.²³⁸⁰ Interconnection requests require significant financial commitments from the interconnection customer (*e.g.*, application fees, study deposits, and site control requirements), which the Commission made more stringent in Order No. 2023,²³⁸¹ and therefore we find it unlikely that an interconnection customer would submit multiple interconnection requests (in multiple queue cycles) in order to trigger this requirement because of the possibility that transmission providers may eventually develop an interconnection-related network upgrade by selecting it in a regional transmission plan for purposes of cost allocation. An interconnection customer would face several risks in pursuing such a strategy, including the risk that the regional transmission solution for the interconnection-related transmission need is not selected, and the risk that the newly created interconnection or transmission capacity is allocated to a different transmission or interconnection customer. For these reasons, we decline to adopt Invenergy's request to modify the proposal to require that withdrawn interconnection requests must have been submitted by unaffiliated entities.²³⁸²

1120. In response to Eversource's request that the Commission clarify that submitting and withdrawing interconnection requests with the intent of requiring transmission providers to evaluate the associated interconnection-related transmission needs in their regional transmission planning process is in violation of the Commission's regulations, including but not limited to the duty of candor and prohibition of market manipulation,²³⁸³ as noted above, the generator interconnection process requires significant financial commitments for interconnection requests to enter and proceed in the queue, and many transmission providers have imposed additional readiness requirements to encourage early withdrawal of non-viable interconnection requests. For these reasons, we disagree with the gaming concerns raised by Eversource.²³⁸⁴

²³⁸⁰ Ameren Initial Comments at 18; American Municipal Power Initial Comments at 33–34; EEI Initial Comments at 18; Idaho Power Initial Comments at 6; PJM Initial Comments at 89.

²³⁸¹ *See, e.g.*, Order No. 2023, 184 FERC ¶ 61,054 at P 502.

²³⁸² Invenergy Reply Comments at 14–15.

²³⁸³ Eversource Initial Comments at 23–24 (citing 18 CFR 35.41; 18 CFR 1c.2).

²³⁸⁴ While we are not concerned about gaming here, to the extent that there is evidence of a false representation or gaming of the market rules, a referral to the Office of Enforcement may be

²³⁷⁵ NRECA Reply Comments at 10–11.

²³⁷⁶ CAISO Reply Comments at 29; NRECA Reply Comments at 9; PJM Initial Comments at 87.

²³⁷⁷ APPA Initial Comments at 31; Industrial Customers Initial Comments at 13; NRECA Initial Comments at 41–42 (citation omitted); NRECA Reply Comments at 8–9; PJM Initial Comments at 89–90; Vistra Initial Comments at 8; Xcel Initial Comments at 15.

²³⁷⁸ TAPS Initial Comments at 13–14.

²³⁷⁹ Ameren Initial Comments at 18–19; American Municipal Power Initial Comments at 34; Dominion Initial Comments at 32; Dominion Reply Comments at 7–8; EEI Initial Comments at 18; Eversource Initial Comments at 23–24; Idaho Power Initial Comments at 6; Pennsylvania Commission Initial Comments at 9; PJM Initial Comments at 89; PPL Initial Comments at 12–13; Shell Initial Comments at 29–30; SPP Initial Comments at 16; Xcel Initial Comments at 16.

1121. We also grant SEIA's request to clarify that the phrase "interconnection-related transmission needs" allows transmission providers to identify individual regional transmission solutions to address each identified interconnection-related transmission need, or an aggregate regional transmission solution to address multiple interconnection-related transmission needs. In response to commenters arguing that the reforms issued under Order No. 2023 will address interconnection-related issues more appropriately than the NOPR proposal,²³⁸⁵ we explain that the reforms in this rulemaking are intended to address situations when interconnection-related network upgrades are repeatedly identified but not constructed and instances when regional transmission solutions to address the needs that would have been addressed by those interconnection-related network upgrades would provide widespread transmission benefits that extend beyond the interconnection customer, which are not addressed in Order No. 2023.

B. Transmission Planning Process Evaluation

1. NOPR Proposal

1122. In the NOPR, the Commission proposed to require the transmission providers in each transmission planning region to consider regional transmission facilities that address interconnection-related transmission needs pursuant to the proposed coordination reform through the Long-Term Regional Transmission Planning process proposed in the NOPR. Specifically, the Commission proposed to require that transmission providers in each transmission planning region incorporate the specific interconnection-related transmission needs identified through the coordination reform as a factor used to develop Long-Term Scenarios in the Long-Term Regional Transmission Planning proposed in the NOPR.²³⁸⁶

2. Comments

1123. Several commenters assert that the NOPR proposal is unnecessary because well-executed Long-Term Regional Transmission Planning will identify the transmission needed to

support interconnections.²³⁸⁷ For example, Xcel argues that Long-Term Scenarios will be driven by the same factors that cause interconnection customers to make interconnection requests, such as optimal geographic locations for generation development.²³⁸⁸ Similarly, EEI states that Long-Term Regional Transmission Planning, if properly implemented, already takes into account factors that support generator interconnection.²³⁸⁹

1124. Some of these commenters further claim that the Commission's coordination proposal's reliance on backward-looking interconnection needs would be less effective than planning on future system interconnection needs. CAISO argues that the Commission's proposal is backward-looking and therefore will not promote productive, forward-looking transmission planning.²³⁹⁰ Vistra claims that an effective transmission planning process will identify interconnection needs and provide solutions within the context of a future system, rather than relying on prior interconnection studies addressing a specific generator interconnection request.²³⁹¹ Similarly, ISO/RTO Council recommends that the Commission direct transmission planners to consider generator interconnection as a driver of Long-Term Transmission Needs on a forward-looking basis, rather than the coordination proposal's backwards-looking process.²³⁹²

1125. MISO states that because the generator interconnection process is designed to identify the minimum amount of interconnection-related network upgrades to interconnect new resources, Long-Term Regional Transmission Planning is the proper avenue to holistically evaluate system needs. MISO notes that it already has a mechanism in place to include interconnection-related network upgrades in its Long-Range Transmission Plan process if the interconnection-related network upgrade is found to have region-wide benefits.²³⁹³

3. Commission Determination

1126. We adopt the NOPR proposal, with modification, to require

²³⁸⁷ AEP Initial Comments at 19; EEI Initial Comments at 18; ENGIE Initial Comments at 5; Illinois Commission Initial Comments at 8–9; Vistra Initial Comments at 33; Xcel Initial Comments at 15.

²³⁸⁸ Xcel Initial Comments at 15.

²³⁸⁹ EEI Initial Comments at 18.

²³⁹⁰ CAISO Initial Comments at 6, 34–35.

²³⁹¹ Vistra Initial Comments at 33.

²³⁹² ISO/RTO Council Initial Comments at 9.

²³⁹³ MISO Initial Comments at 44, 46–47; MISO Reply Comments at 29.

transmission providers in each transmission planning region to evaluate regional transmission facilities that address certain interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes instead of in Long-Term Regional Transmission Planning. We find that this modification will better alleviate transmission limitations by providing a starting point for identifying and evaluating regional transmission solutions that are more efficient or cost-effective when analyzed in the near term.²³⁹⁴ Specifically, requiring transmission providers to evaluate identified interconnection-related transmission needs in existing Order No. 1000 regional transmission planning and cost allocation processes will allow such needs to be addressed within a timeframe that is relevant for identifying more efficient or cost-effective near-term regional transmission solutions. Evaluation of interconnection-related transmission needs in the existing Order No. 1000 regional transmission planning and cost allocation processes is most appropriate because such evaluation would occur at shorter intervals and would likely result in more expeditious development of regional transmission facilities to address the nearer-term interconnection-related transmission needs identified through the generator interconnection process.

1127. We agree with commenters that future interconnection-related transmission needs will be considered as part of Long-Term Regional Transmission Planning and incorporated in the development of Long-Term Scenarios. Nonetheless, for the reasons described above, we find that current interconnection-related transmission needs can be considered more effectively through the nearer-term existing Order No. 1000 regional transmission planning and cost allocation processes. As such, we disagree with commenters that assert that the Commission's proposal is unnecessary because well-executed Long-Term Regional Transmission Planning will identify the transmission needed to support generator interconnections.²³⁹⁵ That said, we emphasize that, as transmission providers gain experience with Long-Term Regional Transmission Planning, we anticipate that they will identify

²³⁹⁴ See NOPR, 179 FERC ¶ 61,028 at P 165.

²³⁹⁵ AEP Initial Comments at 18–19; EEI Initial Comments at 18; ENGIE Initial Comments at 5; Illinois Commission Initial Comments at 8–9; Vistra Initial Comments at 33; Xcel Initial Comments at 15.

appropriate to determine whether a violation of the Commission's regulations has occurred.

²³⁸⁵ Dominion Reply Comments at 8; Idaho Power Initial Comments at 6–7; Illinois Commission Initial Comments at 8; Pacific Northwest Utilities Initial Comments at 15.

²³⁸⁶ NOPR, 179 FERC ¶ 61,028 at P 167.

fewer interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process because transmission providers will plan to address Long-Term Transmission Needs, including those driven by Factor Category One: Federal, federally-recognized Tribal, state, and local laws and regulations that affect the future resource mix and demand; Factor Category Two: Federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification; Factor Category Six: generator interconnection requests and withdrawals, and Factor Category Seven: utility and corporate commitments and Federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs, through Long-Term Regional Transmission Planning.

1128. Some commenters, including Vistra and ISO/RTO Council, claim that the NOPR proposal to rely on needs identified in prior interconnection studies would be less effective at planning for interconnection-related transmission needs compared to more future-oriented approaches. We agree that an effective regional transmission planning process will identify interconnection-related transmission needs and evaluate regional transmission solutions to those needs within the context of a future system. We further agree that transmission providers should consider generator interconnection as a driver of Long-Term Transmission Needs on a forward-looking basis. For these reasons, we require transmission providers to incorporate seven specific categories of factors in their development of Long-Term Scenarios used in Long-Term Regional Transmission Planning, including Factor Category Six: generator interconnection requests and withdrawals. However, we disagree that the coordination proposal should not rely on past results from the generator interconnection process or specific interconnection requests in determining what interconnection-related transmission needs should be evaluated in the existing Order No. 1000 regional transmission planning and cost allocation processes. Interconnection-related network upgrades repeatedly identified in past interconnection studies are strongly indicative that a location (despite presenting potentially prohibitive interconnection costs if borne by one or a small number of interconnection customers) is otherwise valuable for location of new generation.

1129. Finally, because we are modifying the NOPR proposal to no longer apply to Long-Term Regional Transmission Planning, commenters' specific concerns that this proposal is duplicative to the categories of factors requirements in the development of Long-Term Scenarios are moot.

C. Qualifying Criteria

1. NOPR Proposal

1130. In the NOPR, the Commission proposed to require that transmission providers evaluate for selection regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where: (1) the transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years (beginning at the time of the withdrawal of the first underlying interconnection request); (2) the interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV and/or an estimated cost of at least \$30 million; (3) those interconnection-related network upgrades have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the upgrade has been withdrawn; and (4) the transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related transmission need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the transmission provider file unexecuted with the Commission.²³⁹⁶

1131. The Commission proposed that the initial five-year time period begin five calendar years prior to the initial effective date of the Commission-accepted tariff provisions proposed to comply with this reform such that, upon the Commission's acceptance of such tariff provisions, the transmission provider would consider interconnection-related network upgrades identified to address the same interconnection-related transmission need in at least two interconnection queue cycles in the five calendar years

prior to the effective date established in the order accepting those tariff revisions.²³⁹⁷ The Commission also proposed to require that transmission providers in each transmission planning region consider whether the interconnection-related transmission need for which the transmission provider identified the interconnection-related network upgrade is the same in multiple interconnection queue cycles.²³⁹⁸ That is, if an interconnection-related transmission need is driving the identification of an interconnection-related network upgrade on the transmission system in one interconnection queue cycle and an interconnection-related network upgrade with, for example, a different voltage, starting point, or ending point is identified in the next interconnection queue cycle to address the same interconnection-related transmission need, then the first criterion of the proposed coordination reform would be satisfied.²³⁹⁹ The Commission stated that it believes that this approach will appropriately account for differences in technology, study assumptions, system topology, and/or interconnection requests that may occur over time that may result in different interconnection-related network upgrades to address the same interconnection-related need.²⁴⁰⁰

1132. The Commission stated that it believes that the proposed criteria the transmission provider must use to identify the interconnection-related transmission needs that should be considered in the regional transmission planning process will help to ensure that the associated interconnection-related network upgrades are likely to have produced benefits beyond those provided to the interconnection customers whose interconnection requests the interconnection-related network upgrades are needed to accommodate.²⁴⁰¹

1133. To avoid shifting costs inappropriately from generators in the generator interconnection process to transmission customers through the regional transmission planning process, the Commission further proposed to limit the scope of interconnection-related transmission needs to be considered in the regional transmission planning process to those interconnection-related transmission needs not addressed by interconnection-related network upgrades memorialized in an executed generator

²³⁹⁷ *Id.* P 170.

²³⁹⁸ *Id.* P 171.

²³⁹⁹ *Id.*

²⁴⁰⁰ *Id.*

²⁴⁰¹ *Id.* P 168.

²³⁹⁶ NOPR, 179 FERC ¶ 61,028 at P 166.

interconnection agreement (or in a generator interconnection agreement that the interconnection customer requested to be filed unexecuted with the Commission).²⁴⁰²

2. Comments

1134. Multiple commenters generally support the NOPR proposal but express concerns about the eligibility criteria proposed in the NOPR and request modification.²⁴⁰³ SDG&E states that the criteria defined in the NOPR strike an appropriate balance to cover many situations in which generation is needed, while also protecting ratepayers from unnecessary costs.²⁴⁰⁴

1135. Avangrid argues that, while the NOPR proposal has merit, the Commission should allow transmission providers to determine the most appropriate thresholds.²⁴⁰⁵ SEIA asks the Commission to allow each transmission planning region to determine its own threshold, which may include lower voltage lines and substations.²⁴⁰⁶ Indicated PJM TOs further argue that the proposed criteria may not be appropriate in all transmission planning regions.²⁴⁰⁷

1136. MISO argues that transmission planning regions should be able to develop their own cost and voltage criteria. MISO explains that it may be difficult to implement the requirement that interconnection-related network upgrades that qualify must “not currently be planned to be developed” in the interconnection process because in MISO’s experience interconnection-related network upgrades shift from queue cycle to queue cycle as withdrawals occur, and as a result MISO suggests deleting this requirement. MISO opposes the requirement to identify any interconnection-related network upgrade that is identified in multiple generator interconnection studies as it would require the review and comparison of numerous studies to comply with no increased benefit.²⁴⁰⁸

1137. Multiple commenters that generally support the NOPR proposal suggest modification to the NOPR’s proposed cost and voltage eligibility criteria. Pattern Energy suggests that the Commission should allow consideration

of interconnection-related network upgrades that would meet either a voltage or a cost threshold because, for example, lower voltage lines that cost more than \$30 million can often satisfy an interconnection need.²⁴⁰⁹ Pattern Energy and Pine Gate argue that the Commission should lower the voltage threshold to 100 kV.²⁴¹⁰ Shell asks the Commission to lower the 200 kV threshold to 115 kV or to remove it entirely in favor of a cost threshold that is updated regularly based on inflation or some other Commission-approved indicator.²⁴¹¹

1138. Pine Gate argues that the Commission should reduce the cost threshold to \$10 million.²⁴¹² SEIA argues that the cost threshold should be replaced with a \$100,000/MW threshold.²⁴¹³ US DOE argues that a \$30 million cost threshold may not be appropriate because some interconnection-related network upgrades that meet this eligibility factor may only benefit a limited number of interconnection customers. As an alternative, US DOE adds that the Commission should consider interconnection-related network upgrades “that would provide benefits beyond the local interconnection level or that would improve interconnection efficiencies across a wider geographic area and not substations, voltage support devices, or other local connection upgrades.”²⁴¹⁴

1139. Dominion states that the relatively low voltage and cost thresholds in the Commission’s proposal invites interconnection customers to seek bigger investments than needed or select a location that increases the cost of interconnection.²⁴¹⁵ Dominion further argues that the number, size, or frequency of interconnection requests should not be used as a basis for planning transmission projects, because the process could be subject to gaming, where speculative interconnection requests could result in transmission buildouts and spending that are not justified by actual grid needs or economics.²⁴¹⁶

1140. Some commenters take issue with the NOPR’s proposed criteria. Indicated PJM TOs argue that there is no record evidence to support the proposed 200 kV and \$30 million cost threshold

criteria.²⁴¹⁷ PJM states that few interconnection studies have identified the need for interconnection-related network upgrades in excess of \$30 million.²⁴¹⁸ Illinois Commission contends that many projects in the interconnection queue are associated with interconnection-related network upgrades that meet the repeatedly-identified and 200 kV thresholds and that simply folding interconnection costs into transmission planning may expedite the queue at the expense of efficiency and cost-effectiveness.²⁴¹⁹ Indicated PJM TOs argue that limiting consideration to only generating facilities that have not yet signed (or had filed) an interconnection agreement will result in studying only uneconomic projects, which would run afoul of the cost causation principle.²⁴²⁰

1141. Interwest argues that the Commission should not require the identification of the interconnection-related network upgrade in two queue cycles over the five-year lookback period because such a requirement would limit the number of identified interconnection-related network upgrades that would trigger this newly proposed process.²⁴²¹ Pine Gate states that the Commission’s look-back period should be at least the two immediately preceding interconnection queue cycles, or, where serial studies have been performed, during the preceding five years beginning at the time of the withdrawal of the first underlying interconnection request.²⁴²² Pine Gate argues that this revision will ensure that study results will be available for use in identifying interconnection-related network upgrades to evaluate.²⁴²³ SEIA argues that once a transmission provider identifies the same interconnection-related network upgrade in two interconnection cycles, that line should be included in the next Long-Term Regional Transmission Planning update cycle even if five years have not passed since initial identification.²⁴²⁴ Pattern Energy supports SEIA’s requests.²⁴²⁵

1142. EEI and Eversource are unsure of the stage of the generator interconnection process at which a project would meet the proposed criteria.²⁴²⁶ Eversource requests that the

²⁴⁰² *Id.* P 173.

²⁴⁰³ NARUC Initial Comments at 19–20; Pattern Energy Initial Comments at 28; Pine Gate Initial Comments 31–33; SEIA Initial Comments at 14–15; Shell Initial Comments at 30; TAPS Initial Comments at 13; US DOE Initial Comments at 28.

²⁴⁰⁴ SDG&E Initial Comments at 3.

²⁴⁰⁵ Avangrid Initial Comments at 12.

²⁴⁰⁶ SEIA Initial Comments at 15.

²⁴⁰⁷ Indicated PJM TOs Initial Comments at 15–16.

²⁴⁰⁸ MISO Initial Comments at 45–46.

²⁴⁰⁹ Pattern Energy Initial Comments at 28.

²⁴¹⁰ Pattern Energy Initial Comments at 28; Pine Gate Initial Comments at 32.

²⁴¹¹ Shell Initial Comments at 30.

²⁴¹² Pine Gate Initial Comments at 32.

²⁴¹³ SEIA Initial Comments at 15.

²⁴¹⁴ US DOE Initial Comments at 28.

²⁴¹⁵ Dominion Initial Comments at 32.

²⁴¹⁶ Dominion Reply Comments at 7–8.

²⁴¹⁷ Indicated PJM TOs Initial Comments at 15.

²⁴¹⁸ PJM Initial Comments at 88.

²⁴¹⁹ Illinois Commission Initial Comments at 8–9.

²⁴²⁰ Indicated PJM TOs Initial Comments at 16.

²⁴²¹ Interwest Initial Comments at 3, 11.

²⁴²² Pine Gate Initial Comments at 31.

²⁴²³ *Id.*

²⁴²⁴ SEIA Initial Comments at 15.

²⁴²⁵ Pattern Energy Reply Comments at 10–11.

²⁴²⁶ EEI Initial Comments at 17–18; Eversource Initial Comments at 24.

Commission require transmission providers to specify the stage in the interconnection process that an interconnection-related network upgrade is identified.²⁴²⁷

1143. Pine Gate asks the Commission to combine the third and fourth criteria into one criterion: those interconnection-related network upgrades that are not developed or in development and not currently committed to be built under an interconnection service agreement or any related construction agreement.²⁴²⁸

1144. Some commenters argue that the Commission's proposed criteria create too simplistic of a method for determining which interconnection-related network upgrades should be evaluated in Long-Term Regional Transmission Planning.²⁴²⁹ Pennsylvania Commission argues that, without a rigorous examination of why an interconnection application failed, there is no proof that there exists a need for building interconnection-related network upgrades as part of Long-Term Regional Transmission Planning.²⁴³⁰ NARUC argues that the meaning of the term "multiple times" should be informed by a process that also examines the reasons why the previous interconnection requests were withdrawn, including generation developer land acquisition decisions or the identification of more economic transmission design alternatives.²⁴³¹ Vistra takes issue with the fact that the Commission does not distinguish between situations when developers simply sought to develop in an uneconomic area versus when a more efficient or cost-effective transmission project would have been identified as part of the regional transmission planning process.²⁴³²

3. Commission Determination

1145. We adopt the NOPR proposal, with modification, to require that, for a regional transmission facility to address an interconnection-related transmission need to qualify for evaluation through the regional transmission planning process for selection under this reform, any interconnection-related network upgrade identified to meet that interconnection-related transmission need must meet both the proposed voltage and cost criteria. Thus, we

require transmission providers to evaluate for selection in their existing Order No 1000 regional transmission planning processes regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where: (1) the transmission provider has identified interconnection-related network upgrades in interconnection studies to address those interconnection-related transmission needs in at least two interconnection queue cycles during the preceding five years (looking back from the effective date of the Commission-accepted tariff provisions proposed to comply with this reform, and the later-in-time withdrawn interconnection request occurring after the effective date of the Commission-accepted tariff provisions); (2) an interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV and an estimated cost of at least \$30 million; (3) such interconnection-related network upgrade(s) have not been developed and are not currently planned to be developed because the interconnection request(s) driving the need for the network upgrade(s) has been withdrawn; and (4) the transmission provider has not identified an interconnection-related network upgrade to address the relevant interconnection-related transmission need in an executed generator interconnection agreement or in a generator interconnection agreement that the interconnection customer requested that the transmission provider file unexecuted with the Commission.

1146. We find it necessary to establish these criteria to limit the scope of the requirement for transmission providers to evaluate regional transmission facilities to address interconnection-related transmission needs in their regional transmission planning processes to those interconnection-related transmission needs that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. We find that each of the four criteria are necessary to identify the appropriate set of interconnection-related transmission needs. Moreover, we find that the modification to require that an interconnection-related network upgrade identified to meet an

interconnection-related transmission need must satisfy both the voltage and cost thresholds better limits the scope of this reform by ensuring that any regional transmission facilities evaluated to address such interconnection-related transmission needs are more likely to provide widespread benefits to transmission customers.²⁴³³

1147. We further find that these criteria strike a reasonable balance between precision and workability. Our reforms here are intended to ensure that transmission providers must identify interconnection-related transmission needs for evaluation in their regional transmission planning processes that are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. Requiring in-depth qualitative analysis of individual interconnection requests, including consideration of why they were withdrawn, as some commenters suggest, would undermine these goals. Furthermore, these criteria simply determine whether transmission providers must *evaluate* regional transmission facilities to address any given interconnection-related transmission need for potential selection; transmission providers may still separately assess whether any particular regional transmission facility qualifies for selection in the relevant existing regional transmission planning process(es). Therefore, we disagree with commenters that argue that the proposed criteria create too simplistic a method for determining which interconnection-related transmission needs should be evaluated in regional

²⁴³³ The Commission has previously found that network upgrades can benefit all transmission customers. See Order No. 2003, 104 FERC ¶ 61,103 at PP 21, 65 (stating "[m]ost improvements to the Transmission System, including Network Upgrades, benefit all transmission customers" and "the definition of Network Upgrade [includes] the phrase 'at or beyond the Point of Interconnection,' . . . [f]acilities beyond the Point of Interconnection are part of the Transmission Provider's Transmission System and benefit all users"); Order No. 2003-A, 106 FERC ¶ 61,220 at P 584 (citing *Entergy Servs., Inc. v. FERC*, 319 F.3d 536, 543–544 (D.C. Cir. 2003)). The Commission has also previously found, and the record demonstrates, that higher-voltage transmission facilities are more likely to provide widespread benefits to transmission customers. See NOPR, 179 FERC ¶ 61,028 at PP 32 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 486), 168; *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252, at P 73 (2010); *Midwest Indep. Trans. Sys. Operator, Inc.*, 129 FERC ¶ 61,060, at P 8 (2009). See also, e.g., CAISO ANOPR Comments at 54; Invenenergy Initial Comments at 14; Southeast PIOs Initial Comments at 24.

²⁴²⁷ Eversource Initial Comments at 24.

²⁴²⁸ Pine Gate Initial Comments at 32–33.

²⁴²⁹ NARUC Initial Comments at 19; Pennsylvania Commission Initial Comments at 8; Vistra Initial Comments at 20.

²⁴³⁰ Pennsylvania Commission Initial Comments at 8.

²⁴³¹ NARUC Initial Comments at 19.

²⁴³² Vistra Initial Comments at 20.

transmission planning and cost allocation processes.²⁴³⁴

1148. We decline to allow transmission providers to determine appropriate qualifying criteria,²⁴³⁵ because the record supports our adoption of the qualifying criteria established by this order. As described directly above, we find that these specific criteria ensure that the interconnection-related transmission needs that we require transmission providers to evaluate through their regional transmission planning processes are likely to persist, are not unique to a single interconnection request, and might be addressed by regional transmission facilities that have the potential to provide more widespread benefits to transmission customers. Furthermore, transmission providers retain the flexibility to determine whether to select a regional transmission facility, and these criteria will simply determine whether transmission providers, pursuant to this final order, must evaluate interconnection-related transmission needs in the Order No. 1000 regional transmission planning and cost allocation processes.

1149. We also disagree with Indicated PJM TOs' argument that the proposed criteria may not be appropriate in all transmission planning regions because of the differences in scales, topology, and economics.²⁴³⁶ While each transmission planning region is unique, we find that the criteria that we establish here are broad enough to capture interconnection-related network upgrades that are likely to produce benefits beyond the interconnection customer across transmission planning regions despite their differences. Furthermore, as stated above, transmission providers in each transmission planning region retain the flexibility to select regional transmission facilities, and the criteria that we adopt here do not mandate that the transmission providers in any transmission planning region select any particular regional transmission facilities to address interconnection-related transmission needs.

1150. Additionally, we find that the qualifying criteria that we establish here that an interconnection-related need must be repeated twice and meet both voltage and cost thresholds are just and

reasonable. We disagree with commenters that argue for the adoption of different criteria or for the elimination of one or both criteria.²⁴³⁷ We find that the purpose of the criteria established here is precisely to limit the number of interconnection-related transmission needs that transmission providers must evaluate to those that merit consideration in the existing Order No. 1000 regional transmission planning and cost allocation processes. The requirement of the repeat identification of an interconnection-related need in at least two interconnection queue cycles during the preceding five years criterion provides an important limit on the extent to which evaluation is required. Namely, this and the other criteria together indicate that it is likely that the relevant interconnection-related transmission needs will persist but were not resolved because the high associated interconnection-related network upgrade costs drove the withdrawal of the underlying interconnection requests. The repeat identification of interconnection-related network upgrades driven by a common interconnection-related transmission need also indicates that the constraint that the interconnection-related network upgrades were identified to address is not unique to a single interconnection request at a single point in time. Additionally, relaxing this repeat identification requirement may be overburdensome to transmission providers because it could increase the number of interconnection-related transmission needs that transmission providers must evaluate in their regional transmission planning and cost allocation processes.

1151. We find that it is necessary to establish a cost threshold criterion that is stringent enough to capture those interconnection-related network upgrades that are likely to have caused the underlying interconnection requests to withdraw. Additionally, we find that it is necessary to establish a voltage criterion that is high enough so that any regional transmission facility evaluated to address the underlying interconnection-related transmission need(s) is likely to produce benefits that extend beyond the interconnection customer. We further believe that these criteria are important to limit the number of interconnection-related transmission needs that transmission

providers must evaluate to a practical set so that transmission providers do not have to evaluate numerous regional transmission facilities to address those needs that are unlikely to be selected.

1152. Consequently, the modification adopted here to require that an interconnection-related network upgrade identified to meet an interconnection-related transmission need satisfies both the voltage and cost criteria will achieve these results. In particular, this modification will prevent transmission providers from evaluating interconnection-related transmission needs associated with interconnection-related network upgrades that are either above 200 kV but lower-cost or cost more than \$30 million but are less than 200 kV, which means that they are less likely to provide more widespread benefits to transmission customers.

1153. The change to the voltage and cost criteria also address commenters' concerns.²⁴³⁸ For example, as US DOE notes, in some instances, network upgrades that cost \$30 million or more may only benefit a limited number of interconnection customers.²⁴³⁹ Consequently, the change that we adopt to require that an interconnection-related network upgrade identified to meet an interconnection-related transmission need satisfy both the voltage and cost criteria will more narrowly define a set of interconnection-related transmission needs that the transmission provider must evaluate in the regional transmission planning process.

1154. The record supports a 200 kV threshold. For example, as noted in the NOPR, the Commission has previously found CAISO's use of a 200 kV threshold was just and reasonable for determining eligibility for evaluating interconnection-related network upgrades in the regional transmission planning process. The Commission found that CAISO's proposed threshold "strikes a reasonable balance between . . . accommodating the generators' need to interconnect . . . in a timely manner, and the benefits that can flow from evaluating the larger projects in the comprehensive transmission planning process."²⁴⁴⁰ As such, we continue to believe that a 200 kV voltage threshold is sufficiently high such that the interconnection-related network upgrades can more reasonably be expected to produce regional benefits to

²⁴³⁴ See NARUC Initial Comments at 19; Pennsylvania Commission Initial Comments at 3; Vistra Initial Comments at 20.

²⁴³⁵ See Avangrid Initial Comments at 12; MISO Initial Comments at 45–46; SEIA Initial Comments at 15.

²⁴³⁶ See Indicated PJM TOs Initial Comments at 15–16.

²⁴³⁷ See Dominion Initial Comments at 32; Indicated PJM TOs Initial Comments at 15; Interwest Initial Comments at 3, 11; Pattern Energy Initial Comments at 28; Pine Gate Initial Comments at 32; SEIA Initial Comments at 15; Shell Initial Comments at 30.

²⁴³⁸ Pine Gate Initial Comments at 32; SEIA Initial Comments at 15; US DOE Initial Comments at 28.

²⁴³⁹ US DOE Initial Comments at 28.

²⁴⁴⁰ *Cal Indep. Sys. Operator Corp.*, 133 FERC ¶ 61,224, at P 103 (2010); see also NOPR, 179 FERC ¶ 61,028 at P 165 n.300 & P 172 n.302.

transmission customers than lower-voltage transmission facilities.

1155. We also continue to believe that \$30 million is an appropriate threshold for the cost criteria related to this requirement. We find that the \$30 million threshold is consistent with the record established in this proceeding regarding how the costs of interconnection-related network upgrades lead to interconnection customers withdrawing from the queue.²⁴⁴¹ A lower cost criterion may require transmission providers to evaluate in the regional transmission planning process interconnection-related transmission needs associated with interconnection-related network upgrades that have a greater likelihood to be affordable for interconnection customers. Additionally, we are concerned that the \$/kW cost threshold proposed by SEIA may not capture interconnection-related network upgrades that are more likely to provide regional benefits to transmission customers beyond the interconnection customer. Further, transmission providers may face practical challenges in identifying the specific kW size corresponding to the interconnection-related transmission need associated with an interconnection-related network upgrade because the same interconnection-related network upgrade can be identified as needed for multiple interconnection requests (or groups of requests) of different kW sizes.

1156. Additionally, we reiterate that the criteria adopted herein do not require transmission providers to select any particular regional transmission facility to address interconnection-related transmission needs. Instead, we require transmission providers to simply evaluate regional transmission facilities to address interconnection-related transmission needs that meet these criteria for potential selection, recognizing that transmission providers may ultimately determine through their regional transmission planning processes that such regional transmission facilities are not eligible or sufficiently beneficial to be selected.

1157. We disagree with Indicated PJM TOs' argument that limiting evaluation to exclude interconnection-related network upgrades identified in generator interconnection requests that have executed (or requested to be filed unexecuted) an interconnection agreement will result in studying only uneconomic projects.²⁴⁴² This criterion ensures that transmission providers are not required to evaluate in their regional

transmission planning process interconnection-related transmission needs associated with interconnection-related network upgrades for which an interconnection customer has already agreed to pay.²⁴⁴³ Furthermore, in response to MISO's suggestion to delete this limiting aspect, we clarify that this criterion excludes instances in which an interconnection-related network upgrade is identified in an executed generator interconnection agreement (or in a generator interconnection agreement that the interconnection customer requested to be filed unexecuted with the Commission),²⁴⁴⁴ not instances where an interconnection-related network upgrade that meets the criteria in this section is identified as needed for an interconnection request that has not proceeded to the generator interconnection agreement phase of the interconnection study process.

1158. The criterion requiring that interconnection-related transmission needs are identified in at least two interconnection queue cycles during the preceding five years will help to ensure that an interconnection-related transmission need is likely to persist and is not unique to a single interconnection request before requiring transmission providers to evaluate a regional transmission facility to address that need for potential selection.²⁴⁴⁵ We recognize that, in limited circumstances, it is possible that there may be only one interconnection queue cycle during a five-year period. We clarify that if more than five years pass between interconnection queue cycles, then this criterion should be read to include the interconnection queue cycle that immediately preceded the current interconnection queue where the interconnection-related transmission need is identified.²⁴⁴⁶

1159. We adopt the NOPR proposal that the initial five-year period will begin five calendar years prior to the effective date of the Commission-accepted tariff provisions proposed to comply with this final order. Thus, transmission providers must evaluate an interconnection-related transmission need that has been previously identified multiple times within the five years prior to the effective date of the Commission-accepted tariff provisions, but never been resolved due to the withdrawal of the underlying interconnection request(s). This

assumes that the other qualifying criteria are met for the interconnection-related transmission need. The evaluation for selection of regional transmission facilities that address certain identified interconnection-related transmission needs must occur in the first Order No. 1000 regional transmission planning and cost allocation processes cycle that commences after the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions.

1160. Additionally, we clarify that if there are no queue cycles in the preceding five-year period because the transmission provider uses a first-come, first-served serial interconnection process, then this criterion will be met based on the identification of interconnection-related transmission needs in individual interconnection studies. That is, if the interconnection-related transmission need is identified in at least two individual interconnection studies during the preceding five-year period for interconnection customers that subsequently withdrew from the interconnection queue, then this criterion is met. We further clarify, as discussed immediately above, that if a transmission provider identifies the same interconnection-related transmission need in two interconnection queue cycles during a five-year period or less, the transmission provider must evaluate that interconnection-related transmission need even if five years have not yet passed since the initial identification.²⁴⁴⁷

1161. In response to Eversource's request that we require transmission providers to specify the stage in the generator interconnection process that an interconnection-related network upgrade is identified,²⁴⁴⁸ we clarify that the criterion discussed herein applies no matter the stage in which the upgrades are identified, because we are concerned with interconnection-related transmission needs going unaddressed due to withdrawals regardless of the stage of the generator interconnection process.

1162. Finally, we decline to combine the third and fourth criteria into one criterion as Pine Gate suggests, because we find that it is unnecessary.²⁴⁴⁹ This reform creates a process for the evaluation of interconnection-related

²⁴⁴³ NOPR, 179 FERC ¶ 61,028 at P 173.

²⁴⁴⁴ MISO Initial Comments at 46.

²⁴⁴⁵ Pattern Energy Reply Comments at 10–11; Pine Gate Initial Comments at 31; SEIA Initial Comments at 14–15.

²⁴⁴⁶ See Pine Gate Initial Comments at 31.

²⁴⁴⁷ See Pattern Energy Reply Comments at 10–11; SEIA Initial Comments 15.

²⁴⁴⁸ See EEI Initial Comments at 17–18; Eversource Initial Comments at 24.

²⁴⁴⁹ See Pine Gate Initial Comments at 32–33.

²⁴⁴¹ NOPR, 179 FERC ¶ 61,028 at P 172 n.303.

²⁴⁴² Indicated PJM TOs Initial Comments at 16.

transmission needs in regional transmission planning and cost allocation processes if those needs have not been addressed and are unlikely to be addressed through the development of an interconnection-related network upgrade in the generator interconnection process. The purpose of the third criterion is to limit the reform to those interconnection-related transmission needs where the associated interconnection requests have been withdrawn; that is, this criterion requires the repeat withdrawal. The fourth criterion, that the interconnection-related network upgrade not be identified in a generator interconnection agreement, ensures that the interconnection-related network upgrade has not been developed and is not planned to be developed because a generator interconnection agreement memorializes the transmission owner's obligation to develop an identified interconnection-related network upgrade.²⁴⁵⁰

V. Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices

A. General Proposal

1. NOPR Proposal

1163. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to consider two specific technologies more fully in regional transmission planning and cost allocation processes: dynamic line ratings and advanced power flow control devices. The Commission recognized that selecting transmission facilities that incorporate such technologies serving a transmission function in the regional transmission plan for purposes of cost allocation could be more efficient or cost-effective than a proposed regional transmission facility that does not use such technologies.²⁴⁵¹

1164. More specifically, the Commission proposed to require transmission providers in each transmission planning region to consider for each identified regional transmission need whether selecting transmission facilities that incorporate dynamic line ratings or advanced power flow control devices would be more efficient or cost-effective than selecting transmission facilities that do not incorporate these technologies. The Commission proposed that such

consideration should first address whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other transmission facilities that are being considered for potential selection. Second, the Commission proposed that, when evaluating transmission facilities for potential selection, transmission providers in each transmission planning region must also consider whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional transmission facility would be more efficient or cost-effective than potential regional transmission facilities that do not incorporate such technologies. The Commission proposed to apply this requirement in all aspects of the regional transmission planning processes, including the existing regional transmission planning process for near-term regional transmission needs and Long-Term Regional Transmission Planning. As is the case for any other transmission facility selected, the Commission proposed that the costs to incorporate dynamic line ratings or advanced power flow control devices selected, whether as an addition to an existing transmission facility or as part of a new regional transmission facility, be allocated using the applicable regional cost allocation method.²⁴⁵²

1165. The Commission noted that, as required by Order No. 1000, the evaluation process must culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected.²⁴⁵³ The Commission proposed to extend this requirement such that transmission providers must ensure that the determination of whether to incorporate dynamic line ratings and advanced power flow control devices is sufficiently detailed for stakeholders to understand why they were or were not incorporated into selected regional transmission facilities.²⁴⁵⁴

1166. The Commission also sought comment on whether non-RTO/ISO transmission planning regions should be required to update their energy management systems or make other similar changes if dynamic line ratings

are identified as a more efficient or cost-effective transmission facility.²⁴⁵⁵

2. Comments on General Proposal

1167. Many commenters, including technology developers, environmental advocates, ratepayer advocates, and independent market monitors, support the NOPR proposal.²⁴⁵⁶ For example, many commenters state that these technologies provide significant annual cost savings²⁴⁵⁷ or affect both the capital investment and consumer benefits of cost allocation.²⁴⁵⁸ Additionally, some Federal legislators support the NOPR proposal.²⁴⁵⁹ CARE

²⁴⁵⁵ *Id.* P. 277.

²⁴⁵⁶ ACEG Initial Comments at 31; ACORE Initial Comments at 15–16; ACORE Supplemental Comments at 1; Advanced Energy Buyers Initial Comments at 4; AEE Initial Comments at 27–28; CARE Coalition Initial Comments at 2–3; Certain TDUs Reply Comments at 7–9; Clean Energy Associations Initial Comments at 28; Clean Energy Associations Reply Comments at 7–8; Conservative Energy Network Supplemental Comments at 1–2; Conservatives for Clean Energy—Florida Supplemental Comments at 1–2; Conservatives for Clean Energy—South Carolina Supplemental Comments at 1; Cross Sector Representatives Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 36; DC and MD Offices of People's Counsel Reply Comments at 8–9; Evergreen Action Initial Comments at 4; Hannon Armstrong Reply Comments at 2; Illinois Commission Initial Comments at 11–13; Indicated US Senators and Representatives Initial Comments at 2; Joint Consumer Advocates Initial Comments at 13; Massachusetts Attorney General Initial Comments at 16–18; Michigan Conservative Energy Forum Supplemental Comments at 1; Michigan State Entities Initial Comments at 10; NARUC Initial Comments at 35; NASEO Initial Comments at 6; NASUCA Initial Comments at 7–8; NESCOE Initial Comments at 53; Nevada Commission Initial Comments at 13; Ohio Conservative Energy Forum Supplemental Comments at 1; Pennsylvania Commission Initial Comments at 11; PIOs Initial Comments at 22; PJM Market Monitor Initial Comments at 6; Potomac Economics Initial Comments at 5; Prysmian Initial Comments at 1; Smart Wires Initial Comments at 1; SPP Market Monitor Initial Comments at 9; US DOE Initial Comments at 36–37; WATT Coalition Initial Comments at 2; WATT Coalition Supplemental Comments at 2–3; Western Way Colorado Supplemental Comments at 1–2; Western Way Nevada Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

²⁴⁵⁷ Cross Sector Representatives Supplemental Comments at 1; WATT Coalition Supplemental Comments at 2–3.

²⁴⁵⁸ Conservative Energy Network Supplemental Comments at 1–2; Conservatives for Clean Energy—Florida Supplemental Comments at 1–2; Conservatives for Clean Energy—South Carolina Supplemental Comments at 1; Michigan Conservative Energy Forum Supplemental Comments at 1; Ohio Conservative Energy Forum at 1; Western Way Colorado Supplemental Comments at 2; Western Way Nevada Supplemental Comments at 2; Western Way Utah Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

²⁴⁵⁹ Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2; Senator Whitehouse Supplemental Comments at 3.

²⁴⁵⁰ See *Pro forma* LGIA art. 11.3 (“Transmission Provider or Transmission Owner shall design, procure, construct, install, and own the Network Upgrades . . . described in Appendix B.”).

²⁴⁵¹ NOPR, 179 FERC ¶ 61,028 at PP 272–273.

²⁴⁵² *Id.* P. 274.

²⁴⁵³ *Id.* P. 275 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 328; Order No. 1000–A, 139 FERC ¶ 61,132 at P 267).

²⁴⁵⁴ *Id.*

Coalition asserts that the Commission should use all available tools and technologies to increase the efficiency and capacity of the transmission network.²⁴⁶⁰ ELCON states that transmission planning processes should ascertain whether current infrastructure can be improved before reviewing costlier or slower options like greenfield transmission, and greater weight should be given to those transmission projects that incorporate grid enhancing technologies.²⁴⁶¹ Certain TDUs state that they participate actively in the MISO transmission planning process, and that they have observed that grid enhancing technologies and other non-transmission alternatives do not receive the attention that they deserve.²⁴⁶² AEE contends that the Commission has an obligation to promote the adoption of alternative transmission technologies, as directed by Congress in the Energy Policy Act of 2005, and AEE states that the Commission has not made explicit efforts to implement this mandate beyond offering rate incentives for alternative transmission technologies.²⁴⁶³

1168. Industrial Customers assert that requiring dynamic line ratings, advanced power flow control devices, and other grid enhancing technologies will require transmission utilities to deploy capital where it is needed most to maintain reliability, which will reduce transmission costs to consumers because dynamic line ratings extend the useful life of existing transmission infrastructure and optimize existing grid capabilities.²⁴⁶⁴ ENGIE claims that deploying grid enhancing technologies could help to contain costs and support efficient, advanced projects.²⁴⁶⁵ Invenery argues that, even if there may be instances where dynamic line ratings and advanced power flow control devices do not provide the best option with respect to cost, transmission providers should still undertake the analysis.²⁴⁶⁶ Potomac Economics observes that incorporating grid enhancing technologies in the transmission planning process will help ensure that transmission owners do not incur inefficient transmission upgrade costs to mitigate congestion that can be reduced more cost-effectively by grid enhancing technologies.²⁴⁶⁷

1169. Individual state governmental entities as well as NASEO, NASUCA, and NESCOE emphasize the importance of considering more efficient or cost-effective alternatives.²⁴⁶⁸ Some state commissions and US DOE cite the benefits of cost containment for customers.²⁴⁶⁹ DC and MD Offices of People's Counsel and Clean Energy Associations assert that grid enhancing technologies provide value beyond lowering transmission costs, as they can be deployed quickly, are modular, have low environmental and geographic footprints, and can be developed at low risk.²⁴⁷⁰ NARUC asserts that an effective transmission planning process should maximize the use of existing transmission and allow for building new transmission only where necessary or economic.²⁴⁷¹ Indicated US Senators and Representatives support the use of advanced transmission technologies to increase the efficiency and resilience of the electric grid.²⁴⁷²

1170. Many commenters support the consideration of alternative transmission technologies in transmission planning. For example, Certain TDUs argue that the Commission must protect ratepayers and consider all alternatives to ensure safe, reliable, and cost-effective transmission solutions, including the use of alternative transmission technologies.²⁴⁷³ Invenery avers that there may be instances where better using these technologies may require certain foundational investments (e.g., appropriate software), but that only reinforces the need to establish a requirement to drive change.²⁴⁷⁴ Industrial Customers state that transmission providers should have to consider grid enhancing technologies whenever additional transmission investment is the alternative because the cost of installing them will almost always be nominal compared to the benefits of reduced congestion, lower energy and capacity costs, and reduced

need for increases in transmission system capability.²⁴⁷⁵

1171. WATT Coalition asserts that alternative transmission technologies and new transmission capacity are complementary.²⁴⁷⁶ WATT Coalition and Industrial Customers further assert that there is substantial value in considering dynamic line ratings in Long-Term Regional Transmission Planning because they can provide data to strengthen assumptions made in the planning process.²⁴⁷⁷ Specifically, WATT Coalition explains that historical data sets of dynamic transmission line ratings can be analyzed to create probabilistic line ratings on a seasonal, monthly, or more granular level to inform the transmission planning process, helping to maximize its efficiency.²⁴⁷⁸ Finally, WATT Coalition states that the use of forecasted ambient-adjusted ratings (Ambient Adjusted Ratings) demonstrates that more granular data inputs can and should be captured to increase the value of new transmission investment, as well as increased reliability and market efficiency.²⁴⁷⁹

1172. Invenery states that, if there are concerns about the burden associated with evaluating alternative transmission technologies, the Commission could adopt a reasonable threshold under which transmission providers are required to consider whether dynamic line ratings, advanced power flow control devices, and other grid enhancing technologies may be more efficient or cost-effective. For example, Invenery suggests that, if an overload is identified and the relevant facilities are overloaded by 20% or less, the transmission provider should be required to consider grid enhancing technologies as a solution. Invenery urges the Commission to reject calls to make the proposal an optional process, noting that transmission providers can already consider these technologies, but many do not.²⁴⁸⁰

²⁴⁶⁸ Massachusetts Attorney General Initial Comments at 16–18; Michigan State Entities Initial Comments at 10 (citing Institute for Policy Integrity ANOPR Reply Comments at 8); NASEO Initial Comments at 6; NASUCA Initial Comments at 7–8; NESCOE Initial Comments at 53.

²⁴⁶⁹ Illinois Commission Initial Comments at 11–13; NARUC Initial Comments at 35–36; Nevada Commission Initial Comments at 13; Pennsylvania Commission Initial Comments at 11; US DOE Initial Comments at 36–37.

²⁴⁷⁰ Clean Energy Associations Initial Comments at 27; DC and MD Offices of People's Counsel Reply Comments at 8.

²⁴⁷¹ Industrial Customers Reply Comments at 12; NARUC Initial Comments at 35.

²⁴⁷² Indicated US Senators and Representatives Initial Comments at 2.

²⁴⁷³ Certain TDUs Reply Comments at 8.

²⁴⁷⁴ Invenery Reply Comments at 17.

²⁴⁷⁵ Industrial Customers Reply Comments at 16.

²⁴⁷⁶ WATT Coalition Reply Comments at 2.

²⁴⁷⁷ Industrial Customers Reply Comments at 18; WATT Coalition Reply Comments at 1–3 (citing Appendix B of its Reply Comments).

²⁴⁷⁸ WATT Coalition Reply Comments Appendix B at 12. For example, WATT Coalition reports that ERCOT uses historical dynamic line rating data in its regional transmission plan. *Id.* (citing ERCOT 2021 Regional Transmission Plan Report, section 1.2, https://www.ercot.com/files/docs/2021/12/23/2021_Regional_Transmission_Plan_Report_Public.zip).

²⁴⁷⁹ *Id.* Appendix B at 13.

²⁴⁸⁰ Invenery Reply Comments at 16–17.

²⁴⁶⁰ CARE Coalition Initial Comments at 3.

²⁴⁶¹ ELCON Initial Comments at 5, 20.

²⁴⁶² Certain TDUs Reply Comments at 8.

²⁴⁶³ AEE Initial Comments at 29 (citing 42 U.S.C. 16422).

²⁴⁶⁴ Industrial Customers Reply Comments at 13–14.

²⁴⁶⁵ ENGIE Reply Comments at 3–4.

²⁴⁶⁶ Invenery Reply Comments at 17.

²⁴⁶⁷ Potomac Economics Initial Comments at 5.

1173. Some commenters express partial support for the NOPR proposal but raise concerns about certain aspects.²⁴⁸¹ California Water supports consideration of dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning but recommends that any final order clarify that such technologies should be adopted only if they are considered in the regional transmission planning process as the Commission proposes, serve the purpose of cost containment, and are found to be efficient and cost-effective.²⁴⁸² TAPS states that while it supports the implementation of grid enhancing technologies, they may be better suited for consideration on a shorter regional transmission planning horizon.²⁴⁸³ While Pattern Energy supports the consideration of grid enhancing technologies in Long-Term Regional Transmission Planning, it similarly notes that dynamic line ratings and advanced power flow control devices are shorter-term transmission solutions—helping to “squeeze more” out of the infrastructure that is operating or planned to be constructed.²⁴⁸⁴

1174. While ENGIE supports the Commission’s proposal to require the evaluation and deployment of dynamic line ratings and advanced power flow control devices where beneficial in Long-Term Regional Transmission Planning, it notes that the operational data used by such devices are not yet easily incorporated into the transmission planning framework.²⁴⁸⁵ Similarly, SEIA and Invenergy raise concerns that utilities struggle to consider, evaluate, and select these technologies as transmission solutions due to a lack of information about how they might be integrated into the transmission planning process.²⁴⁸⁶

1175. Finally, National Grid generally supports the notion that transmission providers should consider whether and how alternative transmission technologies can be incorporated into transmission planning and states that such technologies, in certain instances, may offer a more efficient or cost-effective alternative to other regional

transmission facilities.²⁴⁸⁷ However, National Grid states that, if the Commission adopts in a final order the requirement to fully consider dynamic line ratings and advanced power flow control devices, it should explain how it expects RTOs/ISOs to implement the first step of the consideration process articulated in the NOPR, *i.e.*, that the alternative transmission technologies being incorporated into existing transmission facilities “could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities.”²⁴⁸⁸ According to National Grid, such a requirement would exceed the RTO/ISO’s authority as the independent administrator of the competitive solicitation process.²⁴⁸⁹

1176. Many commenters oppose the NOPR proposal.²⁴⁹⁰ Some commenters warn the Commission of the potential reliability and operational impacts of the widespread use of dynamic line ratings and advanced power flow control devices.²⁴⁹¹ APPA asserts that transmission dynamic line ratings and advanced power flow control devices should not be required until the industry has further experience with Ambient-Adjusted Ratings deployment.²⁴⁹² Exelon asserts that transmission providers already consider grid enhancing technologies and notes that, in many instances, the selection and deployment of grid enhancing technologies are fundamentally incompatible with the competitive transmission requirements in Order No. 1000, particularly in the context of

development of new transmission facilities, where grid enhancing technologies are unlikely to be the lower cost solution, and may be considerably more expensive than traditional transmission technologies.²⁴⁹³

1177. Some commenters argue that further support is needed to justify any mandate to consider alternative transmission technologies in transmission planning.²⁴⁹⁴ Kansas Commission asserts that any new requirements should be based on a data-driven, robust analysis demonstrating ratepayer benefits; it also cautions against using such technologies as a short-term fix.²⁴⁹⁵ ATC states that the Commission should develop a record of the costs, risks, and potential impacts of widespread implementation of dynamic line ratings before mandating further action.²⁴⁹⁶

1178. Some commenters raise concerns about the costs of alternative transmission technologies. Mississippi Commission argues that mandating the use of technologies without considering their cost is not just and reasonable.²⁴⁹⁷ ATC asserts that the costs of implementing dynamic line ratings system wide would not be nominal.²⁴⁹⁸ US Chamber of Commerce asserts that dynamic line ratings are not a way to obtain “free” transmission capacity because there are costs associated with monitoring the ratings.²⁴⁹⁹

1179. Other commenters argue that the Commission should favor flexibility and not mandate that dynamic line ratings and advanced power flow control devices be considered.²⁵⁰⁰ Georgia Commission states that it is reasonable for the Commission to encourage, rather than require, consideration of dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning.²⁵⁰¹ LADWP suggests that instead of mandating consideration of specific technologies that become obsolete, the Commission

²⁴⁸⁷ National Grid Initial Comments at 21.

²⁴⁸⁸ *Id.* at 23 (quoting NOPR, 179 FERC ¶ 61,028 at P 274).

²⁴⁸⁹ *Id.*

²⁴⁹⁰ AEP Initial Comments at 33; Ameren Initial Comments at 23–24; APPA Initial Comments at 37; ATC Initial Comments at 7–8; Avangrid Initial Comments at 31; DATA Initial Comments at 17; Dominion Initial Comments at 40; Duke Initial Comments at 29–32; EEI Initial Comments at 20–22; Entergy Initial Comments at 26–28; Eversource Initial Comments at 27–28; Exelon Initial Comments at 18–23; Georgia Commission Initial Comments at 7–8; Idaho Power Initial Comments at 9; Indicated PJM TOs Initial Comments at 19–20; ITC Initial Comments at 26–28; ITC Reply Comments at 27; LADWP Initial Comments at 5; Large Public Power Initial Comments at 31–34; MISO TOs Initial Comments at 23–24; Mississippi Commission Reply Comments at 8; New York TOs Initial Comments at 22–23; NRECA Initial Comments at 52; NYISO Initial Comments at 45, 47; OMS Initial Comments at 9; Pacific Northwest Utilities Initial Comments at 15–16; PJM Initial Comments at 105–109; PPL Initial Comments at 22–23; Southern Initial Comments at 35; SERTP Sponsors Initial Comments at 36–37; US Chamber of Commerce Initial Comments at 9.

²⁴⁹¹ Duke Initial Comments at 31–32; Entergy Initial Comments at 27–28; MISO Initial Comments at 59–60.

²⁴⁹² APPA Initial Comments at 5.

²⁴⁹³ Exelon Initial Comments at 21.

²⁴⁹⁴ ATC Reply Comments at 3; Kansas Commission Initial Comments at 19–20.

²⁴⁹⁵ Kansas Commission Initial Comments at 19–20.

²⁴⁹⁶ ATC Reply Comments at 3.

²⁴⁹⁷ Mississippi Commission Reply Comments at 8.

²⁴⁹⁸ ATC Reply Comments at 3 (citing Pattern Energy Initial Comments at 30; Pine Gate Initial Comments at 40–41).

²⁴⁹⁹ US Chamber of Commerce Initial Comments at 9.

²⁵⁰⁰ Avangrid Initial Comments at 31; Clean Energy Buyers Initial Comments at 25; Eversource Initial Comments at 27; Georgia Commission Initial Comments at 7–8; Idaho Power Initial Comments at 9; New York TOs Initial Comments at 23; OMS Initial Comments at 9; PPL Initial Comments at 23.

²⁵⁰¹ Georgia Commission Initial Comments at 7.

²⁴⁸¹ CAISO Initial Comments at 37–39; California Water Initial Comments at 20; ENGIE Initial Comments at 6; Invenergy Initial Comments at 14–16; Ohio Consumers Initial Comments at 32–33; Pattern Energy Initial Comments at 29; SEIA Initial Comments at 21–22; SPP Initial Comments at 25–26; TAPS Initial Comments at 4, 21–22.

²⁴⁸² California Water Initial Comments at 20.

²⁴⁸³ TAPS Initial Comments at 4, 21–22.

²⁴⁸⁴ Pattern Energy Initial Comments at 29.

²⁴⁸⁵ ENGIE Initial Comments at 6.

²⁴⁸⁶ Invenergy Initial Comments at 14–16; SEIA Initial Comments at 21–22.

should require transmission providers to use Good Utility Practice to identify and use technologies that maximize the use of transmission assets in order to minimize impacts to ratepayers and the public.²⁵⁰²

1180. Similarly, National Grid argues that the Commission should not favor the deployment of the two proposed technologies over more efficient or cost-effective transmission facilities, and that focusing on specific technologies is likely to stifle innovation and will not lead to the identification of the more efficient or cost-effective transmission facilities.²⁵⁰³ ATC disagrees with commenters that state that utilities are reluctant to implement these technologies,²⁵⁰⁴ noting that it advocates for and uses advanced power flow control devices and other advanced technologies on its system.²⁵⁰⁵ However, ATC describes widespread dynamic line rating deployment as costly.²⁵⁰⁶

1181. Other commenters urge the Commission to complete its consideration of the record in the Notice of Inquiry on the Implementation of Dynamic Line Ratings²⁵⁰⁷ and/or wait for transmission providers to comply with Order No. 881²⁵⁰⁸ before implementing the NOPR proposal on dynamic line ratings.²⁵⁰⁹ Large Public Power states that the Commission appears to sidestep the record in the Notice of Inquiry on the Implementation of Dynamic Line Ratings, especially the technical and cybersecurity-related concerns in that docket.²⁵¹⁰ MISO TOs state that imposing a mandate in this proceeding would complicate the issue.²⁵¹¹ ATC argues that a more prudent course of action would be to gain experience with Ambient-Adjusted Ratings before moving on to consideration of the use of dynamic line ratings.²⁵¹² ITC asserts that dynamic line ratings and advanced power flow control devices should be implemented on an operational basis through existing

Commission proceedings addressing such technologies.²⁵¹³

1182. Several commenters specifically support the NOPR proposal of requiring consideration of both: (1) whether incorporating dynamic line ratings or advanced power flow control devices into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other transmission facilities that are being considered for potential selection; and (2) whether incorporating dynamic line ratings and advanced power flow control devices as part of any potential regional transmission facility would be more efficient or cost-effective than those without incorporating such technologies.²⁵¹⁴ Ohio Consumers emphasize the importance of considering dynamic line ratings and advanced power flow control devices for both proposed and existing projects, noting that the goal of using these technologies is to lower overall costs of new transmission for consumers, and citing to a DOE study that found that these technologies can defer or reduce the need for significant investment in new infrastructure projects, and increase the use of renewables by maximizing the capacity of current infrastructure.²⁵¹⁵

1183. Others oppose the consideration of alternative transmission technologies on new transmission facilities.²⁵¹⁶ CAISO contends that a requirement to consider whether to incorporate dynamic line ratings and advanced power flow control devices as part of every new regional transmission facility identified to meet a reliability need would create more work without yielding significant benefits because incorporating such measures would not alter the scope of the underlying transmission facilities that are necessary to meet the reliability need.²⁵¹⁷ LADWP

states that identification of specific technologies in a rulemaking seems inappropriate and asserts a transmission line that is not yet built has no operating history, and it should therefore be at the discretion of the transmission planner to consider and implement dynamic line ratings, as it would slow down the design and construction of the transmission line.²⁵¹⁸ Exelon states that, particularly in the context of new transmission facilities, grid enhancing technologies are very unlikely to be the lower cost solution relative to traditional transmission technologies, and for many technologies, they should be expected to be considerably more expensive than traditional transmission technologies (notwithstanding any additional benefits they may offer).²⁵¹⁹

1184. Clean Energy Associations, Industrial Customers, and WATT Coalition support the implementation of a requirement for non-RTO/ISO regions to update their energy management systems if dynamic line ratings are identified as a more efficient or cost-effective transmission facility selected.²⁵²⁰ ELCON agrees, asserting that the Commission's requirement for dynamic line ratings and advanced power flow control devices should apply to all Commission-jurisdictional transmission utilities, regardless of whether they are RTOs/ISOs.²⁵²¹ WATT Coalition adds that all transmission providers should be required to upgrade their energy management systems and keep them consistent across all transmission providers to accommodate the latest technologies.²⁵²² WATT Coalition further states that advanced power flow control devices and topology optimization do not require modifications to existing energy management systems, but that the implementation of such technologies would benefit from the increased flexibility of dynamic line rating-enabled energy management systems.²⁵²³

1185. Pattern Energy states that energy management systems and other equipment will need upgrades to integrate readouts from the dynamic line ratings equipment to minimize operator intervention and enhance operational awareness. Pattern Energy

intended to meet economic or public policy needs. *Id.*

²⁵¹⁸ LADWP Initial Comments at 5.

²⁵¹⁹ Exelon Initial Comments at 21–22.

²⁵²⁰ Clean Energy Associations Initial Comments at 28; Industrial Customers Initial Comments at 32–33; Industrial Customers Reply Comments at 11; WATT Coalition Initial Comments at 7.

²⁵²¹ ELCON Initial Comments at 21.

²⁵²² WATT Coalition Initial Comments at 7.

²⁵²³ *Id.*

²⁵⁰² LADWP Initial Comments at 5.

²⁵⁰³ National Grid Initial Comments at 22–23.

²⁵⁰⁴ ATC Reply Comments at 2 (citing Invenenergy Initial Comments at 15).

²⁵⁰⁵ *Id.* (citing ATC Initial Comments at 7).

²⁵⁰⁶ *Id.* at 3.

²⁵⁰⁷ *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 (2022).

²⁵⁰⁸ *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (2021).

²⁵⁰⁹ ATC Reply Comments at 4–5; Dominion Initial Comments at 40; Large Public Power Initial Comments at 5, 32–33; MISO TOs Initial Comments at 23–24.

²⁵¹⁰ Large Public Power Initial Comments at 32.

²⁵¹¹ MISO TOs Initial Comments at 23.

²⁵¹² ATC Initial Comments at 10.

²⁵¹³ ITC Reply Comments at 27.

²⁵¹⁴ ACORE Initial Comments at 15; Clean Energy Associations Initial Comments at 28; DC and MD Offices of People's Counsel Initial Comments at 36; Industrial Customers Initial Comments at 32–34; Michigan State Entities Initial Comments at 11; NASEO Initial Comments at 6; Ohio Consumers Initial Comments at 34; State Agencies Initial Comments at 17–18.

²⁵¹⁵ Ohio Consumers Initial Comments at 32–34 (citing US DOE, *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact* (Feb. 2022), <https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf>).

²⁵¹⁶ CAISO Initial Comments at 6; LADWP Initial Comments at 5.

²⁵¹⁷ CAISO Initial Comments at 6. CAISO, however, supports considering these technologies in connection with new transmission facilities

surmises, however, that any upgrades necessitated by a final order in this proceeding may be nominal given that dynamic line ratings and advanced power flow control devices should already be readily integrated with upgrades to energy management systems needed to comply with Order No. 881.²⁵²⁴

1186. Some commenters suggest alternative approaches to incorporating alternative transmission technologies into the transmission system. Vistra asserts that the Commission should modify the NOPR proposal to require: (1) the long-term transmission planning evaluation to include a generation capacity expansion scenario that incorporates the potential for enhanced capability through new market services; (2) early input during the transmission planning cycle from independent market monitors and stakeholders on market improvements that could enhance grid operations; and (3) all solicitations for long-term solutions to equally consider non-transmissions solutions that may include generation, technology, or market design changes that could more efficiently or cost-effectively address a need that otherwise would require construction or modification of transmission facilities.²⁵²⁵

1187. Some commenters request that the Commission establish more prescriptive requirements regarding the evaluation of the alternative transmission technologies than those proposed in the NOPR. Invenergy asserts that the NOPR proposal should be expanded to include other technologies and require transmission providers to select alternative transmission technologies when they provide the most efficient option.²⁵²⁶

1188. WATT Coalition urges the Commission to include an operational planning timeframe for topology optimization, dynamic line ratings, and modular advanced power flow control devices, which can all be deployed quickly. WATT Coalition states that the Commission could require consideration of these technologies for the top 5 or 10 most costly or critical constraints on a quarterly basis.²⁵²⁷ WATT Coalition states that market participants should be able to request the use of grid enhancing technologies, and receive an answer from the transmission provider within a defined

period of time, to be evaluated against alternatives used by the transmission provider.²⁵²⁸ WATT Coalition also asserts that grid enhancing technologies should be required in appropriate instances and encouraged through incentives because utilities have little incentive to deploy them under standard cost-of-service regulation,²⁵²⁹ and after implementing this order, the Commission should develop transmission incentives to complement a congestion threshold requirement, driving other creative applications of grid enhancing technologies where they would create the most value to consumers.²⁵³⁰

1189. Some commenters request more requirements regarding evaluation and/or deployment of alternative transmission technologies to meet transmission needs. WATT Coalition states that there are certain transmission technologies that are faster to deploy than traditional lines and urges the Commission to require an annual review of the Long-Term Regional Transmission Planning process and establish a fast track process for solutions with a lead time of less than 12 months and a capital cost of less than \$50 million.²⁵³¹ WATT Coalition further states that the requirement to consider dynamic line ratings and advanced power flow control devices should also apply in any case where transmission capacity is valuable but the costs of a new line are not justified.²⁵³²

1190. Smart Wires and WATT Coalition argue that the Commission should direct transmission providers to: (1) designate advanced power flow control devices as the default solution for projects requiring a series capacitor; (2) “require evaluation of advanced power flow control devices for thermal overloads that fall within 50% of the line rating,” which they argue is when such devices are often most economically advantageous; (3) require evaluation of advanced power flow control devices for interconnection-related network upgrades associated with new load connections, given that these technologies can be used to rebalance flows quickly and adjusted to mirror actual growth; and (4) mandate deployment of advanced power flow control devices as the default solution for voltage stability management on 100-plus mile AC transmission lines.²⁵³³

1191. Some commenters suggest that the Commission should collect additional data and require reporting on the deployment of alternative transmission technologies. PIOs and DC and MD Offices of People’s Counsel ask the Commission to require that transmission providers explain how they considered alternative transmission technologies in the transmission planning process and if they were not used, why.²⁵³⁴ DC and MD Offices of People’s Counsel assert that data collected from dynamic line ratings should be shared with stakeholders to provide transparency as to the necessity or economic efficiency of certain transmission upgrades, and a mechanism should be implemented to independently review the projected costs and benefits of advanced transmission technologies from an efficiency and cost-allocation perspective.²⁵³⁵ NASEO states that the Commission should include a requirement for those seeking to make changes to RTOs/ISOs’ facilities to provide an analysis of the new technologies and how they meet present and expected future challenges, suggesting that RTOs/ISOs be required to consult with US DOE, the DOE national laboratories, and state energy offices to ensure new technologies are incorporated into Long-Term Regional Transmission Planning.²⁵³⁶ Certain TDUs argue that the Commission should require transmission planners to document their evaluation of alternative transmission solutions in the transmission planning process, which should include the methods used to integrate grid enhancing technologies alone or in combination with transmission upgrades.²⁵³⁷

1192. ENGIE recommends that the Commission require transmission providers to provide a report to the Commission every five years on the deployment and operational analysis of grid enhancing technologies to ensure these technologies are being properly evaluated in Long-Term Regional Transmission Planning.²⁵³⁸ R Street suggests that the Commission require the incorporation, not just consideration, of advanced transmission technologies, and should require the inclusion of commercially viable

²⁵²⁴ Pattern Energy Initial Comments at 30 (citing Order No. 881, 177 FERC ¶ 61,179).

²⁵²⁵ Vistra Initial Comments at 32.

²⁵²⁶ Invenergy Reply Comments at 16 (citing Invenergy Initial Comments at 14–17).

²⁵²⁷ WATT Coalition Initial Comments at 5.

²⁵²⁸ *Id.* at 5–6.

²⁵²⁹ WATT Coalition Reply Comments at 3.

²⁵³⁰ WATT Coalition Supplemental Comments at 3.

²⁵³¹ WATT Coalition Initial Comments at 8.

²⁵³² *Id.* at 4.

²⁵³³ Smart Wires Initial Comments at 1, 3–5; WATT Coalition Initial Comments at 3–4.

²⁵³⁴ DC and MD Offices of People’s Counsel Initial Comments at 36; PIOs Initial Comments at 22.

²⁵³⁵ DC and MD Offices of People’s Counsel Initial Comments at 36.

²⁵³⁶ NASEO Initial Comments at 6–7.

²⁵³⁷ Certain TDUs Reply Comments at 8–9 (citing OMS Initial Comments at 9; Certain TDUs Initial Comments at 24).

²⁵³⁸ ENGIE Initial Comments at 6.

technologies on a rolling basis as informed by a regularly updated list of qualifying technologies through, for example, a periodic forum with technology experts from US DOE.²⁵³⁹ SEIA states that the Commission should host regular technical conferences to discuss improvements and innovations in grid enhancing technologies as experience with these technologies grows.²⁵⁴⁰ SEIA states that to determine whether such technologies are feasible, transmission providers should provide the following information to market participants: modeling assumptions, contingency analysis results, asset age, and environmental and footprint constraints.²⁵⁴¹

1193. Pattern Energy states that the Commission should be mindful that limited supplies of dynamic line ratings, advanced power flow control devices, and SCADA-based implementation equipment (and service providers thereto) may cause shortages that will constrain transmission facility developers and owners.²⁵⁴² Pattern Energy adds that, when evaluating the costs to implement such devices, transmission providers may need to assume cost parameters (e.g., cost per mile or cost per installation) for such devices in order to have an “apples-to-apples comparison.”²⁵⁴³

3. Need for Reform

1194. Based on the record, we find that there is substantial evidence to support the conclusion that the Commission’s existing regional transmission planning requirements are unjust, unreasonable, and unduly discriminatory or preferential because they do not require consideration of alternative transmission technologies in the regional transmission planning process. We therefore adopt the preliminary findings in the NOPR concerning the need for reform. Specifically, we find that the Commission’s existing regional transmission planning requirements fail to ensure that transmission providers consider whether to incorporate alternative transmission technologies into regional transmission facilities as part of their regional transmission planning processes and, consequently, fail to ensure that transmission providers are identifying more efficient or cost-effective regional transmission solutions through those processes. As a result, transmission providers overlook

or undervalue the benefits of certain alternative transmission technologies and, in turn, undertake relatively inefficient and less cost-effective investments in transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Accordingly, we find that existing regional transmission planning requirements are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates.

1195. In the NOPR, the Commission stated that commercially available alternative transmission technologies have the potential to improve the operation of new and existing transmission facilities and defer or mitigate the need for new transmission investments.²⁵⁴⁴ However, existing regional transmission planning processes are not necessarily designed to consider the benefits that alternative transmission technologies can provide.²⁵⁴⁵ Commenters state that some transmission providers are reluctant to implement alternative transmission technologies or that alternative transmission technologies are not consistently evaluated in regional transmission planning in a manner commensurate with the benefits that they can provide.²⁵⁴⁶ The failure to consistently consider these technologies in regional transmission planning prevents them from being identified, evaluated, and selected as a more efficient or cost-effective solution to transmission needs, to the detriment of customers that can benefit from their deployment.

1196. The record demonstrates that alternative transmission technologies can provide significant capacity increases when incorporated into transmission facilities, and that such incorporation may provide benefits that outweigh its costs.²⁵⁴⁷ For example, a white paper prepared by the Brattle Group highlights several recent examples in which dynamic line ratings, transmission switching, and advanced power flow control devices were deployed to cost-effectively meet transmission needs in SPP, MISO, and other utility service territories.²⁵⁴⁸

²⁵⁴⁴ NOPR, 179 FERC ¶ 61,028 at P 267.

²⁵⁴⁵ See, e.g., AEE Initial Comments at 29.

²⁵⁴⁶ Certain TDUs Initial Comments at 22–23; Invenery Initial Comments at 15–16; NASUCA Initial Comments at 7; WATT Coalition Initial Comments at 4.

²⁵⁴⁷ See, e.g., WATT Coalition Supplemental Comments at 2–3.

²⁵⁴⁸ The Brattle Group, *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts* 12–15 (Apr. 20, 2023), [https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-](https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf)

Additionally, a recent US DOE case study on dynamic line ratings and advanced power flow control devices estimates that these alternative transmission technologies can provide significant production cost savings, net import savings, and avoided curtailment savings.²⁵⁴⁹

1197. We find that the failure to require transmission providers to consider alternative transmission technologies renders the Commission’s existing regional transmission planning requirements insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates, we are now requiring, pursuant to FPA section 206, that transmission providers consider in Long-Term Regional Transmission Planning and their existing Order No. 1000 regional transmission planning process the alternative transmission technologies discussed below. While the record indicates that some of the alternative transmission technologies enumerated in this final order are sometimes considered in certain transmission planning regions as solutions to specific transmission needs,²⁵⁵⁰ we find that inconsistent consideration of alternative transmission technologies in regional transmission planning results in transmission providers overlooking or undervaluing the benefits that these technologies can provide. We find that the reforms concerning the consideration of alternative transmission technologies that we adopt in this final order will render the Commission’s existing regional transmission planning requirements just and reasonable, because they will result in transmission providers identifying, evaluating, and selecting regional transmission facilities that are more efficient or cost-effective, which will ensure that Commission-jurisdictional rates are just and reasonable.

4. Commission Determination

1198. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes, dynamic line

Enhancing-Technologies-Complement-Transmission-Buildouts.pdf.

²⁵⁴⁹ US DOE, *Grid-Enhancing Technologies: A Case Study on Ratepayer Impact v-x* (Feb. 2022), [https://www.energy.gov/sites/default/files/2022-04/](https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf)

²⁵⁵⁰ See Exelon Initial Comments at 21–23.

²⁵³⁹ R Street Initial Comments at 4.

²⁵⁴⁰ SEIA Initial Comments at 21.

²⁵⁴¹ *Id.* at 22.

²⁵⁴² Pattern Energy Initial Comments at 29–30.

²⁵⁴³ *Id.* at 30.

ratings and advanced power flow control devices for each identified transmission need. We modify the NOPR proposal to require that, in addition to dynamic line ratings and advanced power flow control devices, transmission providers must consider in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes advanced conductors and transmission switching. Thus, under this modification, transmission providers must consider: (1) dynamic line ratings;²⁵⁵¹ (2) advanced power flow control devices;²⁵⁵² (3) advanced conductors;²⁵⁵³ and (4) transmission switching.²⁵⁵⁴ We clarify that transmission providers must consider each of these enumerated technologies when evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities.²⁵⁵⁵ Thus, for each identified transmission need, when evaluating regional transmission facilities for potential selection, transmission providers must consider whether regional transmission facilities that incorporate, or solely consist of, any of the enumerated list of alternative transmission technologies would be

²⁵⁵¹ A dynamic line rating is “a transmission line rating that applies to a time period of not greater than one hour and reflects up-to-date forecasts of inputs such as (but not limited to) ambient air temperature, wind, solar heating, transmission line tension, or transmission line sag.” NOPR, 179 FERC ¶ 61,028 at P 259 n.408 (citations omitted); *see also* Order No. 881, 177 FERC ¶ 61,179 at P 7; *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 at P 1.

²⁵⁵² Advanced power flow control devices serve a transmission function. These devices can help the system operator control power flows over a given path and can include phase shifting transformers (also known as phase angle regulators) and devices or systems necessary for implementing optimal transmission switching. Advanced power flow control devices allow power to be pushed and pulled to alternate lines with spare capacity leading to maximum utilization of existing transmission capacity. NOPR, 179 FERC ¶ 61,028 at P 270 n.437.

²⁵⁵³ Advanced conductors include present and future transmission line technologies whose power flow capacities exceed the power flow capacities of conventional aluminum conductor steel reinforced conductors. *See* Order No. 2023–A, 186 FERC ¶ 61,199 at 631.

²⁵⁵⁴ Transmission switching is the opening or closing of transmission elements to safely route power and direct flows away from congestion, based on pre-existing forward analysis.

²⁵⁵⁵ We note that upgrades to existing transmission facilities include both: (1) the incorporation of an alternative transmission technology into an existing transmission facility with no additional changes to the underlying transmission facility (e.g., adding dynamic line ratings to an existing transmission facility); and (2) the incorporation of an alternative transmission technology into an existing transmission facility as part of a larger set of upgrades (e.g., adding dynamic line ratings to a transmission facility that is also being reconducted with a conventional aluminum conductor steel reinforced conductor).

more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities that do not incorporate these technologies.

1199. However, transmission providers’ evaluation of the enumerated alternative transmission technologies must be consistent with the requirements in their OATTs for other transmission solutions. This means that, for the purposes of Long Term Regional Transmission Planning, transmission providers must evaluate the benefits of incorporating the enumerated alternative transmission technologies into Long-Term Regional Transmission Facilities in the same manner that they evaluate any Long-Term Regional Transmission Facility, and in a manner consistent with the requirements in the Evaluation of Benefits of Regional Transmission Facilities and Evaluation and Selection of Long-Term Regional Transmission Facilities sections of this final order. Accordingly, we require transmission providers to measure the required benefits and any additional benefits the transmission providers elect to measure, as discussed in detail in the Required Benefits section,²⁵⁵⁶ and use those measured benefits in their evaluation processes to determine if a regional transmission facility that incorporates, or solely consists of, any of the enumerated list of alternative transmission technologies would more efficiently or cost-effectively address Long-Term Transmission Needs. As discussed in detail in the Evaluation and Selection of Long-Term Regional Transmission Facilities section,²⁵⁵⁷ that determination would involve applying the transmission providers’ selection criteria, which must, among other things, seek to maximize benefits accounting for costs over time without over-building transmission facilities. Similarly, for the purposes of existing Order No. 1000 regional transmission planning processes, transmission providers must consider the benefits of incorporating the enumerated alternative transmission technologies into transmission facilities in the same way that they currently evaluate regional transmission facilities in those existing processes to determine if a regional transmission facility incorporating any of the enumerated transmission technologies would be a more efficient or cost-effective regional transmission solution.

1200. In response to concerns regarding the mandatory consideration

²⁵⁵⁶ *Supra* Required Benefits section.

²⁵⁵⁷ *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

of the enumerated alternative transmission technologies for new regional transmission facilities,²⁵⁵⁸ and the incremental increase in costs associated with incorporating an alternative transmission technology into new regional transmission facilities or upgrades to existing transmission facilities,²⁵⁵⁹ we reiterate that transmission providers must follow the evaluation process and selection criteria in their tariffs. As explained in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final order, this does not require transmission providers to select any particular Long-Term Regional Transmission Facility to address Long-Term Transmission Needs (*i.e.*, in this case it does not require the selection and deployment of any particular alternative transmission technology with regard to any particular Long-Term Transmission Need).²⁵⁶⁰ We recognize that, in addition to considering the costs and benefits associated with incorporating alternative transmission technologies into transmission facilities, transmission providers must continue to follow Good Utility Practice with regard to planning, evaluating, selecting, constructing, operating, and maintaining all transmission facilities, whether such transmission facilities are considered and implemented through existing regional transmission planning processes or as part of Long-Term Regional Transmission Planning as set forth in this final order.²⁵⁶¹

1201. We find that it is appropriate to require transmission providers to consider whether it may be more efficient or cost-effective to incorporate the enumerated alternative transmission technologies into both new regional transmission facilities and upgrades to existing transmission facilities because the record indicates that such technologies can provide benefits by improving the efficiency of transmission facilities, regardless of whether the facilities are already in-service or yet to be deployed.²⁵⁶² We find that incorporating the enumerated

²⁵⁵⁸ CAISO Initial Comments at 6; Exelon Initial Comments at 21–22.

²⁵⁵⁹ Exelon Initial Comments at 19–20.

²⁵⁶⁰ *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

²⁵⁶¹ *See pro forma* OATT section 28.2 (Transmission Provider Responsibilities) (“The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider’s Transmission System.”).

²⁵⁶² *See* WATT Coalition Supplemental Comments at 2–3.

alternative transmission technologies as upgrades to existing transmission facilities has the potential to make the use of existing transmission infrastructure more efficient and optimize the performance of such infrastructure, mitigating or deferring the need for development of new regional transmission facilities.²⁵⁶³ Adding alternative transmission technologies to new regional transmission facilities may provide cost savings by improving operational efficiency of transmission facilities. Further, incorporating alternative transmission technologies into new transmission facilities may present more benefits and cost less than incorporating such technologies as retrofits after the regional transmission facility is deployed. We further find that requiring transmission providers to consider the enumerated alternative transmission technologies in Long-Term Regional Transmission Planning and existing regional transmission planning processes will ensure that transmission providers more fully consider a broader set of technologies that can address transmission needs more efficiently or cost-effectively.

1202. We clarify that the selection and use any of the enumerated alternative transmission technologies that are incorporated into an existing transmission facility should be treated as an upgrade to an existing transmission facility. Order No. 1000's elimination of any Federal right of right of first refusal for selected transmission facilities does not apply to upgrades to an existing transmission facility.²⁵⁶⁴ Therefore, an incumbent transmission provider would be designated to develop any alternative transmission technology that is selected for incorporation into that incumbent

transmission provider's existing transmission facilities as the more efficient or cost-effective solution.

1203. With respect to alternative transmission technologies added or deployed on a new selected regional transmission facility, we clarify that the transmission developer that is designated to develop the underlying selected regional transmission facility, whether that developer is an incumbent transmission provider or a nonincumbent transmission developer, must also be designated to develop any alternative transmission technologies selected to be incorporated into the regional transmission facility, and thus, would be eligible to use the applicable regional cost allocation method.²⁵⁶⁵ For example, in a competitive bidding model, the transmission developer that submits the winning bid for a selected new regional transmission facility that includes an alternative transmission technology would be eligible to use the regional cost allocation method for that facility, including for the costs of any alternative transmission technologies. Similarly, in a sponsorship model, the transmission developer that sponsors a new regional transmission facility that includes any alternative transmission technologies would be eligible to use the regional cost allocation method for that facility, including for the costs of any alternative transmission technologies, consistent with the selection.

1204. We further clarify that, under a sponsorship model, transmission providers' addition of an alternative transmission technology to a sponsored regional transmission facility proposal that is ultimately selected must not lead to the original sponsored regional transmission facility being labeled as an unsponsored regional transmission facility. Therefore, the sponsoring developer would be eligible to use the regional cost allocation method for the selected new regional transmission facility, as modified with the alternative transmission technology.

1205. We also clarify that, for every competitive transmission development process in a given transmission planning region, transmission providers must identify with sufficient detail in their OATTs the point or points in a given process at which the transmission providers in the transmission planning region will consider the potential use of

alternative transmission technologies, including the point at which qualified transmission developers must submit any proposal to incorporate alternative transmission technologies. This clarification is meant to ensure transparency for competing transmission developers and other stakeholders.²⁵⁶⁶

1206. In response to comments that transmission providers should not be required to consider the enumerated alternative transmission technologies in regional transmission planning processes due to the costs and challenges associated with implementation,²⁵⁶⁷ we find that the examples in the record of implementation of dynamic line ratings, including ERCOT's experience with dynamic line ratings since 2005 and data from Oncor from 2011 to 2013,²⁵⁶⁸ and overall support for the consideration of advanced power flow control devices in transmission planning,²⁵⁶⁹ sufficiently demonstrate that transmission providers are capable of considering the enumerated alternative transmission technologies in Long-Term Regional Transmission Planning and existing regional transmission planning processes. Kansas Commission's position that consideration of alternative transmission technologies in regional transmission planning processes should be data-driven and supported by robust analysis demonstrating benefits is consistent with our determinations here.²⁵⁷⁰ Therefore, transmission providers must consider the incorporation of these enumerated alternative transmission technologies consistent with the specific requirements for analysis and evaluation of benefits in their OATTs, including those applicable to existing regional transmission planning processes and those required in this final order for Long-Term Regional

²⁵⁶³ Pattern Energy Initial Comments at 29.

²⁵⁶⁴ The Commission stated in Order No. 1000 that the non-incumbent transmission developer reforms do not affect the right of an incumbent transmission provider to build, own and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation. In other words, an incumbent transmission provider would be permitted to maintain a Federal right of first refusal for upgrades to its own transmission facilities. Order No. 1000, 136 FERC ¶ 61,051 at P 319 (footnote omitted). The Commission clarified that "the term upgrade means an improvement to, addition to, or replacement of a part of, an existing transmission facility. The term upgrades does not refer to an entirely new transmission facility." Order No. 1000–A, 139 FERC ¶ 61,132 at P 426. The Commission further clarified that the requirement to eliminate a Federal right of first refusal does not apply to any upgrade, even where the upgrade requires the expansion of an existing right-of-way. *Id.* P 427.

²⁵⁶⁵ See FERC, Staff Report, 2017 *Transmission Metrics* 8 (Oct. 6, 2017), <https://www.ferc.gov/sites/default/files/2020-05/transmission-investment-metrics.pdf> (describing the two general types of competitive transmission development processes, the "competitive bidding model" and the "sponsorship model").

²⁵⁶⁶ For example, in a competitive bidding model, transmission providers must make clear whether, and if so when, a qualified transmission developer can propose to incorporate alternative transmission technologies into a bid for a selected Long-Term Regional Transmission Facility. This transparency requirement ensures that competing transmission developers will be treated comparably because they will know whether and when they can propose to incorporate any additional alternative transmission technologies into a bid for a regional transmission facility that has been selected.

²⁵⁶⁷ See, e.g., ATC Reply Comments at 3.

²⁵⁶⁸ Hannon Armstrong Reply Comments at 2–3; WATT Coalition Reply Comments at app. B.

²⁵⁶⁹ Ameren Initial Comments at 24–25; EEI Initial Comments at 20–21; Entergy Initial Comments at 29; Exelon Initial Comments at 23.

²⁵⁷⁰ Kansas Commission Initial Comments at 19–20.

Transmission Planning.²⁵⁷¹ We acknowledge Mississippi Commission's concerns about deploying alternative transmission technologies without consideration of their costs and note that, to the extent that a transmission provider selects a regional transmission facility that incorporates an enumerated alternative transmission technology, the transmission provider would only do so after evaluating the costs and benefits of that transmission facility, including the incorporation of the alternative transmission technology.²⁵⁷²

1207. We disagree with commenter assertions that alternative transmission technologies are only operational tools and that transmission providers cannot rely on any additional capacity created by these technologies for the purpose of meeting transmission needs.²⁵⁷³ We note that Long-Term Regional Transmission Planning and existing regional transmission planning processes are designed to address a variety of needs, including not only reliability needs but also Long-Term Transmission Needs and economic needs. These processes are well-suited to evaluate the economic benefits of the enumerated alternative transmission technologies, which are relevant to assessing whether a regional transmission facility that incorporates such technologies is more efficient or cost-effective than a proposed regional transmission facility that does not use such technologies. We believe that the particular benefit measurement methods that transmission providers must develop, pursuant to requirements discussed below, to evaluate proposed Long-Term Regional Transmission Facilities can be used to measure the economic benefits of incorporating the enumerated alternative transmission technologies into transmission facilities.²⁵⁷⁴ As more fully described above in the Required Benefits section, these benefits include, but are not limited to, methods to measure production cost savings, reduced congestion due to fewer transmission outages, and capacity cost benefits from reduced peak energy losses. Similarly, we find that the enumerated alternative transmission technologies can provide

those economic benefits that are already evaluated in existing regional transmission planning processes. Finally, contrary to commenters' concerns, the record here demonstrates that certain alternative transmission technologies are in some cases capable of enhancing reliability and providing additional capacity.²⁵⁷⁵

1208. In response to concerns about administrative burden and assertions that predictions about benefits are speculative,²⁵⁷⁶ we find that the potential advantages associated with adopting this reform (*i.e.*, identifying more efficient or cost-effective regional transmission solutions) outweigh the potential administrative and analytical burden. As it pertains to dynamic line ratings, the information needed to inform the calculation of dynamic line ratings should be widely available. For example, NREL has published data on annual averages of windspeeds at 10 meters above the ground that could inform predictions for future wind conditions to facilitate calculations of economic benefits.²⁵⁷⁷ For the calculation of the economic benefits associated with dynamic lines ratings, it is appropriate for such calculations to use historical average wind speed and direction data to calculate average increases to transmission line transfer limits for use in benefit calculations. Average predicted wind speeds and direction should be sufficient to inform the transmission provider as to whether the implementation of dynamic line ratings on a specific transmission line may render that line a more efficient or cost-effective regional transmission solution, and such data are widely

available.²⁵⁷⁸ We acknowledge that there is uncertainty with projections of any kind; however, it is not necessary to understand the precise future wind conditions at a specific future period to assess the expected economic benefits associated with the implementation of dynamic line ratings.

1209. In response to arguments that the Commission should favor transmission provider flexibility with respect to consideration of alternative transmission technologies,²⁵⁷⁹ we note that the reforms adopted in this final order provide transmission providers with an appropriate amount of flexibility and do not require the selection of any particular enumerated alternative transmission technology to address any particular transmission need. As previously discussed, this requirement will ensure that transmission providers more consistently consider the costs and benefits associated with incorporating the enumerated alternative transmission technologies into regional transmission facilities. However, we recognize that transmission providers must also continue to follow Good Utility Practice when planning, evaluating, selecting, constructing, operating, and maintaining transmission facilities.

1210. Moreover, we decline to mandate further details on how transmission providers should evaluate the enumerated list of alternative transmission technologies as more efficient or cost-effective solutions to transmission needs, beyond the requirements adopted in this final order. Thus, in response to comments from Smart Wires and WATT Coalition proposing that the Commission mandate either consideration or deployment of advanced power flow control devices in specific situations,²⁵⁸⁰ we find that transmission providers are the appropriate entity to identify, evaluate, and select specific solutions to specific transmission needs.²⁵⁸¹

²⁵⁷¹ See *supra* Evaluation of the Benefits of Regional Transmission Facilities section.

²⁵⁷² Mississippi Commission Reply Comments at 8.

²⁵⁷³ AEP Initial Comments at 6, 33; Indicated PJM TOs Initial Comments at 19; ITC Initial Comments at 6, 26–28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; SERTP Sponsors Initial Comments at 36–37.

²⁵⁷⁴ See *supra* Evaluation of the Benefits of Regional Transmission Facilities section.

²⁵⁷⁵ See *infra* P 1241 for a more detailed discussion of the reliability benefits of dynamic line ratings and advanced power flow control devices; see also Ameren Initial Comments at 24; Bekaert Supplemental Comments at 1–2; CTC Global Initial Comments at 15.

²⁵⁷⁶ ATC Initial Comments at 10; Duke Initial Comments at 30–31 (citing attach. A, Robert Pierce Aff. ¶¶ 8–9); ISO-NE Initial Comments at 40–41; ITC Initial Comments at 26; Kansas Commission Initial Comments at 19–20; Large Public Power Initial Comments at 32–33; MISO Initial Comments at 58; MISO TOs Initial Comments at 24; New York TOs Initial Comments at 22; Pacific Northwest Utilities Initial Comments at 15–16; SERTP Sponsors Initial Comments at 36–37; Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶ 16; US Chamber of Commerce Initial Comments at 9.

²⁵⁷⁷ Data on annual averages of windspeeds at 10 meters above the ground is published by NREL in the form of both maps and tabular data. See NREL, *Wind Resource Maps and Data*, <https://www.nrel.gov/gis/wind-resource-maps.html>. As another example, data on monthly prevailing wind direction is published by the U.S. Department of Agriculture for various cities in all U.S. states in the form of graphical “wind roses.” See U.S. Dep’t. of Agric., National Weather and Climate Center, <https://www.wcc.nrcs.usda.gov/ftpref/downloads/climate/windrose/>.

²⁵⁷⁸ See, e.g., NREL, *Wind Resource Maps and Data*, <https://www.nrel.gov/gis/wind-resource-maps.html>; U.S. Dep’t of Agric., National Weather and Climate Center, <https://www.wcc.nrcs.usda.gov/ftpref/downloads/climate/windrose/>.

²⁵⁷⁹ Avangrid Initial Comments at 31; Clean Energy Buyers Initial Comments at 25; Eversource Initial Comments at 27; Georgia Commission Initial Comments at 7–8; Idaho Power Initial Comments at 9; New York TOs Initial Comments at 23; OMS Initial Comments at 9; PPL Initial Comments at 23.

²⁵⁸⁰ Smart Wires Initial Comments at 1, 3–5; WATT Coalition Initial Comments at 3–4.

²⁵⁸¹ See Order No. 1000, 136 FERC ¶ 61,051 at P 153 (noting that transmission providers retain the ultimate responsibility for transmission planning). As Entergy and Exelon attest, advanced power flow control devices are already considered in some transmission planning processes. See Entergy Initial Comments at 29; Exelon Initial Comments at 23.

1211. In response to commenters urging the Commission to wait for transmission providers to comply with Order No. 881 before implementing the NOPR proposal,²⁵⁸² such concerns are unpersuasive. Public utility transmission providers subject to Order No. 881 are required to implement these requirements by July 12, 2025.²⁵⁸³ As the Compliance Procedures section of the final order states, the date that transmission providers are required to begin considering the enumerated alternative transmission technologies will be the effective date of the applicable tariff provisions submitted to comply with this final order requirement. The final order also states that transmission providers must submit their compliance filings within ten months of the effective date of this final order, which is 60 days from the date of publication in the **Federal Register**. Moreover, even if the compliance submission deadline falls shortly before Order No. 881's implementation deadline, the operative date here is the date that the tariff revisions proposed in a transmission provider's compliance filing to this final order become effective, which is the effective date requested by the submitting transmission provider and accepted by the Commission.²⁵⁸⁴ Consequently, the transmission provider would not need to implement this final order requirement prior to the implementation of Order No. 881 on July 12, 2025 unless it requests, and the Commission accepts, an earlier effective date for its tariff revisions.

1212. Moreover, we find that concerns raised by commenters with respect to the interactions between the requirements that we establish in this final order and Order No. 881 to be speculative. We believe that the requirements to consider the enumerated alternative transmission technologies are separate from (but complementary to) the Commission's requirements in Order No. 881. In Order No. 881, as most relevant here, the Commission required the use of more accurate transmission line ratings using up-to-date forecasts of ambient air temperatures in transmission line ratings. By contrast, regarding the requirement to consider dynamic line ratings in this final order, transmission

providers must consider the benefits associated with additional up-to-date transmission line rating input assumptions, specifically wind speed and direction and solar heating intensity.

1213. We disagree with concerns that any mandate to consider dynamic line ratings in this proceeding might complicate the dynamic line ratings notice of inquiry (NOI) proceeding,²⁵⁸⁵ or that a mandate to consider dynamic line ratings in this proceeding ignores the record, and the technical challenges identified in, the dynamic line ratings NOI proceeding.²⁵⁸⁶ We find such concerns unpersuasive. Any potential future Commission action in the dynamic line ratings NOI proceeding remains hypothetical. Moreover, we expect transmission providers to consider both the benefits of dynamic line rating implementation and the challenges and costs associated with dynamic line rating implementation as part of their consideration of the technology in Long-Term Regional Transmission Planning and their existing regional transmission planning processes.

1214. In response to requests for additional transparency,²⁵⁸⁷ we also adopt the NOPR proposal to expand the existing requirement established in Order No. 1000 for transmission providers' evaluation processes to culminate in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission facility was selected or not selected. Specifically, we adopt the NOPR proposal to require that the determination include an explanation that is sufficiently detailed for stakeholders to understand why dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching were or were not incorporated into selected regional transmission facilities.

1215. With regard to the Commission's request for comment on whether to require non-RTO/ISO transmission planning regions to update their energy management systems or make other similar changes if dynamic line ratings are selected as a more efficient or cost-effective regional transmission facility, we require transmission providers to update their energy management systems, if needed to implement dynamic line ratings or

any of the alternative transmission technologies. We note that some transmission providers in non-RTO/ISO transmission planning regions may already be able to implement the alternative transmission technologies, and, as a result of the Commission's Ambient-Adjusted Rating requirements in Order No. 881,²⁵⁸⁸ may have already updated their energy management systems, and therefore may not need further updates to their energy management systems. However, if a transmission provider must upgrade its energy management systems to implement any of the alternative transmission technologies, then consistent with other requirements in this final order, we require transmission providers to consider any possible energy management system upgrade costs needed to implement the selected alternative transmission technologies as part of their broader consideration of whether transmission facilities that incorporate alternative transmission technologies are more efficient or cost-effective regional transmission solutions. We further reiterate that transmission providers must provide an explanation that is sufficiently detailed for stakeholders to understand why any of the enumerated alternative transmission technologies were, or were not, incorporated into transmission facilities selected in the regional transmission plan for purposes of cost allocation. Moreover, we clarify that this explanation must be sufficiently clear to demonstrate whether the transmission provider did not select transmission facilities that incorporate any of the enumerated alternative transmission technologies, in part or primarily, due to concerns over the costs of upgrading energy management systems.

1216. Finally, we find that WATT Coalition's request to consider incentives for deploying alternative transmission technologies is outside the scope of this proceeding.

B. Specific Alternative Transmission Technologies

1. NOPR Proposal

1217. The Commission sought comment on whether there are other transmission technologies serving a transmission function that should be considered in regional transmission planning and cost allocation processes. The following section discusses comments on specific alternative transmission technologies that transmission providers are required to

²⁵⁸² ATC Reply Comments at 4–5; Dominion Initial Comments at 40; Large Public Power Initial Comments at 5, 32–33; MISO TOs Initial Comments at 23–24.

²⁵⁸³ See *MATL LLP*, 185 FERC ¶ 61,028, at P 10 (2023) (stating that July 12, 2025 is the implementation date of Order No. 881 (citing Order No. 881, 177 FERC ¶ 61,179 at P 361)).

²⁵⁸⁴ See *infra* Compliance Procedures section.

²⁵⁸⁵ MISO TOs Initial Comments at 23–24.

²⁵⁸⁶ Large Public Power Initial Comments at 32.

²⁵⁸⁷ Certain TDUs Reply Comments at 8–9; DC and MD Offices of People's Counsel Initial Comments at 36; ENGIE Initial Comments at 6; PIOs Initial Comments at 22.

²⁵⁸⁸ Order No. 881, 177 FERC ¶ 61,179 at P 84.

consider pursuant to the requirements of this final order.

2. Comments on Specific Technologies

1218. AEE notes that dynamic line ratings implementation will increase capacity and provide significant benefits to customers.²⁵⁸⁹ Michigan State Entities state that dynamic line ratings hold tremendous value for states like Michigan with cold, cloudy winters, during which there is a greater reliance on transmission to move distant wind generation.²⁵⁹⁰

1219. AEE states that dynamic line ratings and similar technologies are so useful because they improve predictability.²⁵⁹¹ AEE further contends that, in the longer-term, changing conditions will necessitate greater transmission deployment and the need for more transmission capacity, but without considering complementary technologies, the transmission buildout may be less efficient.²⁵⁹²

1220. Hannon Armstrong contends that ERCOT's experience with dynamic line ratings since 2005, as well as data from Oncor from 2011 to 2013, demonstrates that this technology can provide significant savings through reduced congestion costs, allow for granular congestion management, and furnish congestion data. According to Hannon Armstrong, real-time dynamic ratings and reliability analysis improve transmission system operation and planning, provide opportunities for congestion mitigation, and could justify the cancellation of planned transmission upgrades. Hannon Armstrong concludes that dynamic line ratings can promote just and reasonable rates without compromising reliability.²⁵⁹³

1221. As mentioned above, some commenters warn the Commission of potential reliability and operational impacts of the widespread use of dynamic line ratings.²⁵⁹⁴ Entergy explains that it has experienced significantly different weather readings at nearby weather sensors and cautions that the 2003 blackout was partially

caused by overestimating the wind in transmission line ratings.²⁵⁹⁵

1222. Some commenters that oppose the use of dynamic line ratings in transmission planning raise concerns about the reliability risks presented by dynamic line ratings.²⁵⁹⁶ PJM argues that dynamic line ratings are inappropriate for addressing reliability needs and may introduce operational risk because, for example, forecasted wind might not materialize and the actual real-time ratings would be lower than forecasted.²⁵⁹⁷ Southern argues that the assumption of dynamic line ratings leading to additional capacity will likely result in reduced system expansion, which could cause reliability problems in the long run.²⁵⁹⁸ Large Public Power and LADWP maintain that there is meaningful cybersecurity risk associated with the communications equipment needed to support dynamic line ratings.²⁵⁹⁹ However, WATT Coalition states that both traditional transmission solutions and grid enhancing technologies can result in problems, so the impact of solutions should be evaluated carefully to ensure that a solution to one problem does not create another.²⁶⁰⁰

1223. Some commenters argue that dynamic line ratings are operational in nature and do not belong in the transmission planning process.²⁶⁰¹ Dominion and Exelon state that a transmission provider must plan and build its system for worst case scenarios, which limits the usefulness of dynamic line ratings in transmission

planning.²⁶⁰² ITC asserts that transmission systems must be planned based on actual transfer capacity under the worst-case scenario, and not on contingent, variable capacity of the type that dynamic line ratings provide.²⁶⁰³ EEI and Entergy note that the inherent variability and unpredictability associated with wind speed, solar heating intensity, and transmission line tension make dynamic line ratings inappropriate for addressing longer-term system planning objectives.²⁶⁰⁴ MISO adds that for transmission planning horizons of five to 20 years or more into the future, it is impossible to predict the real-time conditions on which dynamic line ratings are based.²⁶⁰⁵ NRECA explains that dynamic line ratings are not a substitute for an upgraded or new transmission facility.²⁶⁰⁶

1224. Many opposing commenters argue that the benefits of dynamic line ratings are too speculative.²⁶⁰⁷ MISO states that dynamic line ratings may not always produce the benefits anticipated, explaining that static ratings are typically based on conservative wind speeds and best-case wind direction, so the assumptions used to develop static ratings are not always worst-case.²⁶⁰⁸ ISO-NE asserts that, for example, under summer peak load conditions, the dynamic line rating would be the same as that assumed in the planning study.²⁶⁰⁹ Southern cautions that including dynamic line ratings in transmission planning would likely assume additional capacity that may not materialize in real time, increasing congestion.²⁶¹⁰ Large Public Power and MISO TOs argue that dynamic line ratings do not provide sufficient incremental benefits over Ambient Adjusted Ratings to justify the additional expense.²⁶¹¹

²⁶⁰² Dominion Initial Comments at 40; Exelon Initial Comments at 22.

²⁶⁰³ ITC Initial Comments at 26.

²⁶⁰⁴ EEI Initial Comments at 21; Entergy Initial Comments at 27.

²⁶⁰⁵ MISO Initial Comments at 57–58.

²⁶⁰⁶ NRECA Initial Comments at 52.

²⁶⁰⁷ ATC Initial Comments at 10; Duke Initial Comments at 30 (citing attach. A, Robert Pierce Aff. ¶ 8); ISO-NE Initial Comments at 40–41; ITC Initial Comments at 26; Kansas Commission Initial Comments at 19–20; Large Public Power Initial Comments at 32–33; MISO Initial Comments at 58; MISO TOs Initial Comments at 24; New York TOs Initial Comments at 15–16; SERTP Sponsors Initial Comments at 36–37; Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶¶ 16–17; US Chamber of Commerce Initial Comments at 9.

²⁶⁰⁸ MISO Initial Comments at 58.

²⁶⁰⁹ ISO-NE Initial Comments at 40–41.

²⁶¹⁰ Southern Initial Comments at 35, Ex. 2, Daryl C. McGee at ¶¶ 16–17.

²⁶¹¹ Large Public Power Initial Comments at 32–33; MISO TOs Initial Comments at 24.

²⁵⁸⁹ AEE Reply Comments at 29 (citing US DOE, *Dynamic Line Ratings Report to Congress 2019* 26 (June 2022), https://www.energy.gov/sites/prod/files/2019/08/f66/Congressional_DLR_Report_June2019_final_508_0.pdf).

²⁵⁹⁰ Michigan State Entities Initial Comments at 10.

²⁵⁹¹ AEE Reply Comments at 30 (citing MISO Initial Comments at 57–58).

²⁵⁹² *Id.*

²⁵⁹³ Hannon Armstrong Reply Comments at 2.

²⁵⁹⁴ Duke Initial Comments at 31–32 (citing attach. A, Robert Pierce Aff. ¶ 11); Entergy Initial Comments at 27–28; MISO Initial Comments at 59–60.

²⁵⁹⁵ Entergy Initial Comments at 27–28 (citing U.S. Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* 58 (Apr. 2004)).

²⁵⁹⁶ ATC Initial Comments at 7, 10; Duke Initial Comments at 31; Exelon Initial Comments at 22; Indicated PJM TOs Initial Comments at 19; LADWP Initial Comments at 5; NRECA Initial Comments at 53; PJM Initial Comments at 108–109; Southern Initial Comments at 35 (citing Ex. 2, Daryl C. McGee at ¶ 17); SERTP Sponsors Initial Comments at 36–37.

²⁵⁹⁷ PJM Initial Comments at 108–109.

²⁵⁹⁸ Southern Initial Comments at 35, Ex. 2, Daryl McGee at ¶ 17.

²⁵⁹⁹ LADWP Initial Comments at 5; Large Public Power Initial Comments at 35.

²⁶⁰⁰ WATT Coalition Reply Comments at 4–5.

²⁶⁰¹ AEP Initial Comments at 33; Dominion Initial Comments at 40; Duke Initial Comments at 5; EEI Initial Comments at 21–22; Entergy Initial Comments at 5–6; Exelon Initial Comments at 22; Indicated PJM TOs Initial Comments at 19; ISO-NE Initial Comments at 40–41; ITC Initial Comments at 6, 26–28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); MISO Initial Comments at 57; MISO TOs Initial Comments at 23; NRECA Initial Comments at 52; Pacific Northwest Utilities Initial Comments at 15–16; PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; Southern Initial Comments at 35; SERTP Sponsors Initial Comments at 36–37; US Chamber of Commerce Initial Comments at 9.

1225. Some commenters argue that advanced power flow control devices are appropriate technologies to consider in transmission planning, contrasting them with dynamic line ratings.²⁶¹² Southern states that it generally supports consideration of advanced power flow control devices, and Ameren argues that they may be appropriate in certain circumstances for regional transmission planning.²⁶¹³ Additionally, while WATT Coalition agrees that conductor-mounted advanced power flow control devices are limited in impact, it contends that today's ground-mounted versions can significantly increase transfer capacity and integration of renewables.²⁶¹⁴

1226. Industrial Customers assert that the Commission should compel the use of advanced power flow control devices because they are instrumental to ensuring that transmission lines are fully used to their safest and most efficient potential.²⁶¹⁵ Industrial Customers further argue that the use of advanced power flow control devices will allow for the optimization of transmission lines under various weather conditions.²⁶¹⁶ Smart Wires states that advanced power flow control devices can provide a more affordable means of servicing the type of load growth driving Long-Term Regional Transmission Facilities.²⁶¹⁷ In addition, Smart Wires argues that several system studies have verified that advanced power flow control devices avoid sub-synchronous resonance events on long radial transmission lines, which can result in extensive damage.²⁶¹⁸

1227. In response to the administrative burden of considering advanced power flow control devices specifically, WATT Coalition states that it provides guidance and evidence of successful modeling schemes for such devices.²⁶¹⁹ WATT Coalition argues that advanced power flow control devices are a valuable solution to limitations of power system studies because they can be adjusted by grid operators for unforeseen grid challenges.²⁶²⁰ WATT Coalition adds that advanced power flow control devices have a granular dispatchability that can also support

real-time operational needs, which may differ from those identified in the transmission planning timeframe.²⁶²¹

1228. Similar to dynamic line ratings, many commenters argue that advanced power flow control devices are not appropriate in the transmission planning context and are more appropriate for operational timeframes.²⁶²² Duke and MISO caution against widespread deployment of advanced power flow control devices.²⁶²³ Duke argues that they should be applied judiciously, and that increased deployment creates a greater risk of wide area cascading events by increasing the probability of the system being in a previously unanalyzed state.²⁶²⁴ MISO states that, while advanced power flow control devices work best to address specific isolated issues, it is not feasible to coordinate the operation and deployment of these devices en masse, either manually or automatically. According to MISO, deployment of these devices could create other issues, and thus their operation and deployment must be managed on a holistic basis.²⁶²⁵ MISO further states that advanced power flow control devices could result in continued cascading issues across the system because of the potential widespread impact of adjusting line impedances that may get pushed to other facilities.²⁶²⁶

1229. A number of commenters assert that the Commission should expand the list of alternative transmission technologies that must be considered.²⁶²⁷ Several commenters suggest that the Commission should require transmission providers to consider specific additional technologies in Long-Term Regional

Transmission Planning, including storage that performs a transmission function, advanced conductors, transmission switching, topology optimization, and dynamic reactive power devices.²⁶²⁸ Some Federal legislators agree, offering support for a requirement to consider energy storage, reconductoring using advanced conductors,²⁶²⁹ and topology optimization.²⁶³⁰ AEE argues that expanding the list of technologies that must be considered in transmission planning would fulfill the Commission's obligations under the FPA to encourage the adoption of advanced transmission technologies.²⁶³¹

1230. Several commenters urge the Commission to require that storage be considered.²⁶³² CARE Coalition states that utilities can use storage to defer investments as supply and demand patterns change, allowing them to avoid all-in, 50-year investments in favor of shorter-term flexibility.²⁶³³ CARE Coalition cites a number of ways that storage can improve transmission,

²⁶²⁸ Dynamic reactive power is produced from equipment that can quickly change the Mvar level independent of the voltage level. Thus, the equipment can increase its reactive power production level when voltage drops and prevent a voltage collapse. Static VAR compensators, synchronous condensers, and generators provide dynamic reactive power. FERC, Staff Report, *Principles for Efficient and Reliable Reactive Power Supply and Consumption* 7 (Feb. 4, 2005), <https://www.ferc.gov/sites/default/files/2020-04/20050310144430-02-04-05-reactive-power.pdf>.

²⁶²⁹ Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2.

²⁶³⁰ Environmental Legislators Caucus Supplemental Comments at 2.

²⁶³¹ AEE Reply Comments at 27–28, 34 (citing 42 U.S.C. 16422(b)).

²⁶³² Advanced Energy Buyers Initial Comments at 4; AEP Initial Comments at 33–34; CAISO Initial Comments at 38; California Commission Initial Comments at 38–40 (citing Jennifer Chen & Devin Hartmann, *Transmission Reform Strategy From A Customer Perspective: Optimizing Net Benefits And Procedural Vehicles R Street Policy Study* 7 (May 2022), <https://www.rstreet.org/wp-content/uploads/2022/05/RSTREET257.pdf>); CARE Coalition Initial Comments at 2–3; Clean Energy Associations Initial Comments at 30–31; Conservative Energy Network Supplemental Comments at 1–2; Conservatives for Clean Energy—Florida Supplemental Comments at 1–2; Conservatives for Clean Energy—South Carolina Supplemental Comments at 1; DC and MD Offices of People's Counsel Initial Comments at 36–37; Illinois Commission Initial Comments at 12; Industrial Customers Reply Comments at 11; Joint Consumer Advocates Initial Comments at 13; Michigan Conservative Energy Forum Supplemental Comments at 36; National Grid Initial Comments at 3–4; Ohio Conservative Energy Forum Supplemental Comments at 1; OMS Initial Comments at 9; Western Way Colorado Supplemental Comments at 2; Western Way Nevada Supplemental Comments at 2; Western Way Utah Supplemental Comments at 2; Wisconsin Conservative Energy Forum Supplemental Comments at 1.

²⁶³³ CARE Coalition Initial Comments at 42–43.

²⁶²¹ *Id.*

²⁶²² AEP Initial Comments at 6; Indicated PJM TOs Initial Comments at 19; ITC Initial Comments at 6, 26–28; Louisiana Commission Initial Comments at 14 (citing Potomac Economics Initial Comments at 2); PJM Initial Comments at 8, 106, 108; PPL Initial Comments at 22; SERTP Sponsors Initial Comments at 36–37.

²⁶²³ Duke Initial Comments at 31–32; MISO Initial Comments at 59–60.

²⁶²⁴ Duke Initial Comments at 31–32.

²⁶²⁵ MISO Initial Comments at 59.

²⁶²⁶ *Id.* at 60.

²⁶²⁷ ACEG Initial Comments at 31; ACORE Initial Comments at 16; ACORE Supplemental Comments at 1; AEE Reply Comments at 27–28; BeKaert Supplemental Comments at 1; Breakthrough Energy Initial Comments at 16; CARE Coalition Initial Comments at 2–3; CARE Coalition Reply Comments at 5; Certain TDUs Reply Comments at 8–9; City of New York Reply Comments at 4 (citing PIOs Initial Comments at 84); Clean Energy Associations Initial Comments at 27–28; Clean Energy Associations Reply Comments at 7; CTC Global Initial Comments at 14–15; Industrial Customers Reply Comments at 11; Invenery Initial Comments at 16; Vermont State Entities Initial Comments at 9.

²⁶¹² EEI Initial Comments at 20–21; Entergy Initial Comments at 29; Exelon Initial Comments at 23–24.

²⁶¹³ Ameren Initial Comments at 24–25; Southern Initial Comments, Ex. 2, Daryl C. McGee at ¶ 15.

²⁶¹⁴ WATT Coalition Reply Comments at 4.

²⁶¹⁵ Industrial Customers Reply Comments at 13–14.

²⁶¹⁶ *Id.* at 18–19 (citing PPL, Initial Comments, Docket No. AD22–5–000, at 3 (filed Apr. 25, 2022)).

²⁶¹⁷ Smart Wires Initial Comments at 3–4.

²⁶¹⁸ *Id.* at 1, 4.

²⁶¹⁹ WATT Coalition Reply Comments at 3 (citing app. C).

²⁶²⁰ *Id.* at 4.

including providing voltage support in a transmission-constrained zone, ensuring reliability while repairs are executed, reducing peak loads, increasing capacity on congested lines, directing power flow away from lower capacity transmission lines, and controlling the timing of power flows to remain under thresholds.²⁶³⁴

1231. AEP states that the Commission should require better consideration of storage, noting that the technology has advanced significantly in the past several years, yet is still not being deployed as a transmission alternative. AEP cites two reasons for this: (1) despite the multiple uses and benefits of storage, it is currently categorized as only one of the following—transmission, generation, or distribution, and (2) there is no traditional approach that assesses the viability of storage proposals to solve reliability problems. AEP states that, to solve these problems, the Commission should provide more certainty around these questions, including how to schedule, dispatch, and charge storage, as well as guidance on how to assess the value of storage beyond reliability if, for example, the resource is only needed during certain times of year.²⁶³⁵

1232. Some commenters suggest that the Commission should require consideration of advanced conductors in Long-Term Regional Transmission Planning.²⁶³⁶ CTC Global asserts that advanced conductors should be required to be considered because of their ease of installation onto existing structures, cost savings, lower line sag, and power flow increase.²⁶³⁷ CTC Global adds that even in the case of a total rebuild, advanced conductors can generate more capacity, efficiency, resilience, and reliability than rebuilds using standard conductors.²⁶³⁸ VEIR notes that if the final order requires the consideration of advanced conductors, the Commission should define advanced conductors to include all advanced conductor technologies, including superconductors.²⁶³⁹ Bekaert states that the definition of advanced conductors should extend beyond carbon fiber core technologies to also include steel core technologies, which it

contends can raise ampacity, reduce line losses, and withstand extreme weather conditions, all while offering a cost-effective solution.²⁶⁴⁰

1233. Some commenters suggest that the Commission should require consideration of transmission switching in Long-Term Regional Transmission Planning.²⁶⁴¹ For example, Illinois Commission states that line switching is a tool to make better use of the extant transmission system.²⁶⁴² NASEO states that the use of alternative transmission technologies, including transmission switching, is increasing.²⁶⁴³ However, MISO argues that grid enhancing technologies that introduce automatic topology changes are not appropriate for consideration over transmission planning horizons of 20 years or more because they would be considered remedial action schemes, which MISO and its transmission owners have attempted to reduce as a matter of Good Utility Practice.²⁶⁴⁴

1234. A number of commenters suggest that the Commission should require consideration of topology optimization in Long-Term Regional Transmission Planning.²⁶⁴⁵ Potomac Economics states that network optimization can allow a transmission operator to circumvent a limiting transmission facility and substantially mitigate the associated congestion, averting transmission upgrades that could prove wasteful and inefficient.²⁶⁴⁶ With respect to topology optimization, WATT Coalition recommends that the information provided in the evaluation process should include modeling assumptions, contingency analysis results, asset age and condition, environmental and footprint constraints, etc.²⁶⁴⁷ In contrast, SPP states that technologies that optimize transmission system operation should be considered short-term solutions and not a

replacement for long-term transmission capacity.²⁶⁴⁸

1235. ITC argues that the Commission should encourage transmission providers to modernize transmission planning criteria to better consider dynamic reactive power devices such as static VAR compensators, static synchronous compensators, and unified power flow controllers. ITC asserts that such technologies provide faster response times to changes in voltage and power factor, relative to capacitor banks and mechanically switched compensation schemes.²⁶⁴⁹

1236. Industrial Customers and Ohio Consumers suggest that the Commission should require the consideration of distributed energy resources in Long-Term Regional Transmission Planning.²⁶⁵⁰ Industrial Customers contend that demand response and load-limiting devices should be considered as a way of optimizing the current transmission system, claiming that they are less costly than transmission expansions.²⁶⁵¹ QCo states that the Commission should consider the use of the thermal mass of major buildings as a low-cost method to store energy and provide flexibility to the grid.²⁶⁵²

1237. ENGIE asserts that the Commission should require consideration of dynamic transformer rating technology in Long-Term Regional Transmission Planning.²⁶⁵³

1238. Exelon is concerned that making a list of technologies to consider in transmission planning will result in a “time-consuming check-the-box exercise,” increasing costs and creating litigation opportunities.²⁶⁵⁴

3. Commission Determination

1239. As stated above, we adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to consider dynamic line ratings and advanced power flow control devices in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning processes.

1240. In response to comments that dynamic line ratings are operational in nature and are inappropriate in transmission planning, we continue to believe that there is enough real-world operational experience with dynamic

²⁶³⁴ *Id.* at 42.

²⁶³⁵ AEP Initial Comments at 33–34.

²⁶³⁶ ACEG Initial Comments at 31; ACORE Initial Comments at 16; Breakthrough Energy Initial Comments at 15–19; CTC Global Initial Comments at 15–16; DC and MD Offices of People’s Counsel Initial Comments at 36–37; Indicated US Senators and Representatives Initial Comments at 2; NASEO Initial Comments at 6; Prysman Initial Comments at 1; VEIR Initial Comments at 5–6.

²⁶³⁷ CTC Global Initial Comments at 14–15.

²⁶³⁸ *Id.* at 15.

²⁶³⁹ VEIR Reply Comments at 5.

²⁶⁴⁰ Bekaert Supplemental Comments at 1–2.

²⁶⁴¹ Illinois Commission Initial Comments at 12; NASEO Initial Comments at 6; Potomac Economics Initial Comments at 5.

²⁶⁴² Illinois Commission Initial Comments at 12 (citing Pablo A. Ruiz, The Brattle Group, *Transmission Topology Optimization* (Aug. 21, 2017) https://www.brattle.com/wp-content/uploads/2017/10/7204_transmission_topology_optimization.pdf (Brattle Group Aug. 2017 Report)).

²⁶⁴³ NASEO Initial Comments at 6.

²⁶⁴⁴ MISO Initial Comments at 60.

²⁶⁴⁵ ACORE Initial Comments at 16; CARE Coalition Initial Comments at 2–3; ENGIE Initial Comments at 5–6; Illinois Commission Initial Comments at 11–13 (citing Brattle Group Aug. 2017 Report); Indicated US Senators and Representatives Initial Comments at 2; Potomac Economics Initial Comments at 5; R Street Initial Comments at 4; Tabors Caramanis Rudkevich Initial Comments at 5; WATT Coalition Initial Comments at 6.

²⁶⁴⁶ Potomac Economics Initial Comments at 5.

²⁶⁴⁷ WATT Coalition Initial Comments at 6.

²⁶⁴⁸ SPP Initial Comments at 26.

²⁶⁴⁹ ITC Initial Comments at 28.

²⁶⁵⁰ Industrial Customers Initial Comments at 35; Ohio Consumers Initial Comments at 34.

²⁶⁵¹ Industrial Customers Reply Comments at 11.

²⁶⁵² QCo Initial Comments at 1–3.

²⁶⁵³ ENGIE Initial Comments at 5–6.

²⁶⁵⁴ Exelon Initial Comments at 23–24.

line ratings for transmission providers to be able to reasonably project their likely operations and, as such, the benefits that regional transmission facilities that incorporate dynamic line ratings can provide over the transmission planning horizon.²⁶⁵⁵ Dynamic line ratings have the ability to increase transmission line ratings, and thus permit more economic energy transfers in most intervals,²⁶⁵⁶ which, in turn, could result in benefits (including, but not limited to, production cost savings, reduced congestion due to fewer transmission outages resulting from improved situational awareness, and capacity cost benefits from reduced peak energy losses) that we require transmission providers to evaluate in Long-Term Regional Transmission Planning,²⁶⁵⁷ and in their existing regional transmission planning processes.

1241. We acknowledge commenter concerns about the potential effects that the widespread use of dynamic line ratings or advanced power flow control devices could have on reliability.²⁶⁵⁸ But while these technologies cannot solve all reliability needs, as noted above, the record here demonstrates that alternative transmission technologies are in certain circumstances capable of enhancing reliability and providing additional capacity.²⁶⁵⁹ We recognize that, either dynamic line ratings or advanced power flow control devices, on their own, may be unlikely to resolve certain reliability needs that are assessed based on worst case conditions.²⁶⁶⁰ We also reiterate that nothing in this final order changes transmission providers' obligations to conduct transmission planning in a manner that ensures the long-term reliability of the bulk electric system.²⁶⁶¹ However, we find that dynamic line ratings and advanced power flow control devices can also confer reliability benefits. For example, in Order No. 881, the Commission found that, by accounting for ambient

air temperatures in transmission line ratings, transmission providers can reliably increase power transfer capability, which results in significant reliability benefits.²⁶⁶² Such reliability benefits also apply to dynamic line ratings. Specifically, by accounting for actual wind conditions, dynamic line ratings can also reliably increase transfer capability and thereby provide reliability benefits. Similarly, as Ameren describes, it may be more efficient to use advanced power flow control devices, which can address stability limitations by allowing for greater use of a transmission facility.²⁶⁶³

1242. Additionally, Long-Term Regional Transmission Planning evaluates Long-Term Regional Transmission Facilities based on multiple benefits, and some existing regional transmission planning processes focus on economic benefits, while others may consider multiple benefits, including economic benefits. At a minimum, regional transmission solutions incorporating dynamic line ratings are appropriately considered as part of these processes. Given the potentially substantial economic benefits of dynamic line ratings, we find that it is important for transmission providers to consider dynamic line ratings in Long-Term Regional Transmission Planning and their existing regional transmission planning processes so as to ensure that they identify more efficient or cost-effective regional transmission facilities for selection.

1243. We also disagree with commenters that argue that advanced power flow control devices are not appropriate in the transmission planning context and are more appropriate for operational timeframes. We find that the potential benefits of using advanced power flow control devices are sufficient to merit their consideration in Long-Term Regional Transmission Planning and existing regional transmission planning processes. For example, as Ameren states, where a transmission line is stability-limited from carrying more power, the use of advanced power flow controls may address the limitation and allow greater use of the line. Ameren also notes that advanced power flow controls may be beneficial in a situation where a transmission line that needs to be upgraded traverses sensitive environmental areas.²⁶⁶⁴ Moreover, as Entergy and Exelon attest, advanced power flow control devices are already

considered in some transmission planning processes.²⁶⁶⁵ As discussed above, we modify the NOPR proposal to add two additional alternative transmission technologies to the list of enumerated alternative transmission technologies required to be considered in Long-Term Regional Transmission Planning and existing regional transmission planning: advanced conductors and transmission switching. We find that advanced conductors may greatly increase the capacity of transmission facilities, and thus a new regional transmission facility or upgrade to an existing transmission facility that incorporates advanced conductors may be a more efficient or cost-effective alternative than a proposed regional transmission facility that does not incorporate such technologies. Consistent with Order No. 2023, we note that advanced conductors can increase transmission line ratings, providing more "headroom" on the system to address normal and contingency conditions.²⁶⁶⁶ We clarify that the definition of advanced conductors that we adopt in this final order constitutes a range of permissible present and future technologies, and is defined relative to conventional aluminum conductor steel reinforced conductors. Therefore, advanced conductors include, but are not limited to, superconducting cables, advanced composite conductors, advanced steel cores, high temperature low-sag conductors, fiber optic temperature sensing conductors, and advanced overhead conductors. We find that such advanced conductors can result in lower line sag and increased power flow and can be installed on existing transmission structures, thereby offering ease of installation.²⁶⁶⁷

1244. We agree with commenters that suggest that transmission switching should be added to the list of alternative transmission technologies that must be considered in Long-Term Regional Transmission Planning and existing regional transmission planning processes.²⁶⁶⁸ We clarify that, in this final order, we define transmission switching as the opening or closing of transmission elements to safely route power and direct flows away from congestion, based on pre-existing forward analysis. Transmission switching can be used to route energy around areas with high congestion and

²⁶⁵⁵ NOPR, 179 FERC ¶ 61,028 at P 276.

²⁶⁵⁶ Hannon Armstrong Reply Comments at 1–3.

²⁶⁵⁷ See *supra* Required Benefits section.

²⁶⁵⁸ See, e.g., CAISO Initial Comments at 41–42.

²⁶⁵⁹ See *supra* P 1206 of this section.

²⁶⁶⁰ For example, as ISO-NE explains, the dynamic line rating may be the same as the rating already assumed in the planning study as transmission providers may need to assume worst case weather inputs to transmission line ratings. ISO-NE Initial Comments at 40–41.

²⁶⁶¹ See, for example, TPL-001-5.1, Transmission System Planning Performance Requirements, which establishes transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.

²⁶⁶² Order No. 881, 177 FERC ¶ 61,179 at P 85.

²⁶⁶³ Ameren Initial Comments at 24.

²⁶⁶⁴ *Id.*

²⁶⁶⁵ Entergy Initial Comments at 29; Exelon Initial Comments at 23.

²⁶⁶⁶ Order No. 2023, 184 FERC ¶ 61,054 at P 1597.

²⁶⁶⁷ CTC Global Initial Comments at 14–15.

²⁶⁶⁸ Illinois Commission Initial Comments at 12; NASEO Initial Comments at 6; Potomac Economics Initial Comments at 5.

improve the overall transfer capability of the system. In doing so, transmission switching may provide additional economic or reliability benefits, which could therefore render a transmission facility that uses transmission switching a more efficient or cost-effective alternative than a regional transmission facility that does not use transmission switching. In response to MISO's concern that automatic topology changes are not appropriate for consideration over transmission planning horizons of 20 years or more because they would be considered remedial action schemes,²⁶⁶⁹ we note that there are appropriate applications for transmission switching that offer the potential to be a more efficient or cost-effective alternative than a proposed regional transmission facility that does not use one of the enumerated alternative transmission technologies. For example, the record indicates that network optimization can allow a transmission operator to circumvent a limiting transmission facility and substantially mitigate the associated congestion, averting transmission upgrades that could prove wasteful and inefficient.²⁶⁷⁰

1245. We decline to add storage that performs a transmission function to the list of enumerated alternative transmission technologies. The Commission has determined that the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis of either how a particular electric storage resource would be operated or the requirements set forth in an OATT governing selection of such electric storage resources.²⁶⁷¹ In the context of regional transmission planning, we continue to find that the evaluation of whether an electric storage resource performs a transmission function requires a case-by-case analysis, and therefore decline to generically require the consideration of storage that performs a transmission function in regional transmission planning processes.

1246. For the following reasons, we also decline to add topology optimization to the list of enumerated alternative transmission technologies because it is technically much more challenging to implement. We clarify that topology optimization is not specific to individual transmission facilities but instead is the act of determining the optimal use of the transmission system, which may

involve many different transmission facilities. Additionally, the optimal use of the transmission system may frequently change depending on system conditions throughout the operating day. By contrast, transmission switching focuses on opening or closing transmission elements in pre-determined circumstances based on prior analyses well in advance of the operational time horizon.²⁶⁷² We do not find that it is necessary to require the consideration of topology optimization in regional transmission planning processes currently. While topology optimization software has been used to identify potential system reconfiguration actions that could result in a reduction in real-time congestion, it has not yet been deployed due to computational complexity. Specifically, given the size and complexity of the power grid and the large number of potential optimization solutions, finding optimization solutions in the necessary real-time timelines is extremely difficult and doing so risks poor model performance and lower quality solutions, which, in turn, could adversely impact reliability. While simplifications might be possible, such simplifications risk oversimplifying, which, in turn, could also jeopardize reliability.²⁶⁷³

1247. Finally, we decline to add further additional alternative transmission technologies suggested by commenters.²⁶⁷⁴ We note that, while commenters express support for the concept of considering additional alternative transmission technologies, in general, we do not believe that the record is sufficient to include these additional technologies on the enumerated list of alternative transmission technologies that transmission providers must consider in Long-Term Regional Transmission Planning and existing regional transmission planning processes at this time. However, we note that nothing in this final order precludes transmission providers from considering other alternative transmission technologies or other potential solutions in their Long-Term Regional Transmission Planning

and existing regional transmission planning processes.

VI. Regional Transmission Cost Allocation

A. Cost Allocation for Long-Term Regional Transmission Facilities

1. Cost Allocation Methods for Long-Term Regional Transmission Facilities

a. NOPR Proposal

1248. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to revise their OATTs to include: (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities; (2) a State Agreement Process by which one or more Relevant State Entities²⁶⁷⁵ may voluntarily agree to a cost allocation method; or (3) a combination thereof.²⁶⁷⁶

1249. The Commission proposed to define a Long-Term Regional Transmission Cost Allocation Method as an *ex ante* regional cost allocation method that would be included in each transmission provider's OATT as part of Long-Term Regional Transmission Planning. The developer of a Long-Term Regional Transmission Facility would be entitled to use the Long-Term Regional Transmission Cost Allocation Method if it is the applicable method.²⁶⁷⁷ The Commission proposed to define a State Agreement Process as an *ex post* cost allocation process that would be included in each transmission provider's OATT as part of Long-Term Regional Transmission Planning, which may apply to an individual Long-Term Regional Transmission Facility or a portfolio of such Facilities grouped together for purposes of cost allocation. After a Long-Term Regional Transmission Facility is selected, the State Agreement Process would be followed to establish a cost allocation method for that facility (if agreement

²⁶⁷⁵ The definition of Relevant State Entities is discussed below. *See infra* Requirement that Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section.

²⁶⁷⁶ NOPR, 179 FERC ¶ 61,028 at P 302. The Commission explained that, for example, a "combination" approach may entail: (1) providing a Long-Term Regional Transmission Cost Allocation Method for certain types of Long-Term Regional Transmission Facilities and providing a State Agreement Process for others; or (2) providing for cost allocation for a Long-Term Regional Transmission Facility, portfolio, or type of such facilities partially based on a Long-Term Regional Transmission Cost Allocation Method and partially based on funding contributions in accordance with a State Agreement Process. *Id.* P 302 n.510.

²⁶⁷⁷ *Id.* P 302 n.508.

²⁶⁷² *See supra* P 1243 of this section on transmission switching. We recognize that there may be overlap between the concepts of transmission switching and topology optimization. As noted below, nothing in this final order precludes transmission providers from considering topology optimization solutions as an alternative transmission technology, if they so choose.

²⁶⁷³ US DOE, *Advanced Transmission Technologies* 11–15 (Dec. 2020), <https://www.energy.gov/oe/articles/advanced-transmission-technologies-report>.

²⁶⁷⁴ *See supra* PP 1235–1237.

²⁶⁶⁹ MISO Initial Comments at 60.

²⁶⁷⁰ Potomac Economics Initial Comments at 5.

²⁶⁷¹ Order No. 2023, 184 FERC ¶ 61,054 at P 1599.

can be reached). If the Commission approves the cost allocation method that results from the State Agreement Process, the developer of the Long-Term Regional Transmission Facility would be entitled to use that cost allocation method if it is the applicable method.²⁶⁷⁸

1250. The Commission also proposed to apply the cost allocation reforms only to new Long-Term Regional Transmission Facilities. Therefore, these proposed reforms would neither provide grounds for re-litigation of cost allocation decisions for transmission facilities that are selected prior to the effective date of any final order in this proceeding, nor would they apply to the cost allocation methods associated with regional transmission facilities that address shorter-term transmission needs driven by reliability and/or economic considerations.²⁶⁷⁹

1251. In addition, the Commission stated that, to the extent transmission providers believe that their existing cost allocation approaches comply with the requirements adopted in any final order in this proceeding, including those related to the agreement of Relevant State Entities, they could make such demonstration in their compliance filings in response to any final order.²⁶⁸⁰

b. Comments

i. Interest in the Proposed Cost Allocation Reforms

1252. Some commenters offer general support for the cost allocation reforms proposed in the NOPR.²⁶⁸¹

1253. Several commenters indicate support for the proposal to require transmission providers to revise their OATTs to include: (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities; (2) a State Agreement Process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method; or (3) a combination thereof.²⁶⁸² Clean Energy Buyers state

that this proposal will provide certainty in the cost allocation process, lessening disputes that may delay transmission development.²⁶⁸³ ITC suggests that the Commission look to OMS' role in State Agreement Processes as a guide for how other transmission planning regions can foster state participation in Long-Term Regional Transmission Planning.²⁶⁸⁴ AEP asserts that clear rules set in advance provide the regulatory certainty necessary to support large, long-term transmission investments and ensure customers and developers know how the associated costs will be allocated.²⁶⁸⁵

1254. New Jersey Commission states that a hybrid method that allocates costs partially *ex ante*, based on reliability and economic benefits, and partially *ex post*, through a State Agreement Process/negotiated participant funding approach, could have value, arguing that negotiated cost allocations could reduce litigation and make it easier to construct beneficial transmission facilities.²⁶⁸⁶ SEIA supports a combination of a Long-Term Regional Transmission Cost Allocation Method and a State Agreement Process, asserting that states should be allowed to assume the costs of new transmission facilities to serve their needs.²⁶⁸⁷

ii. Requested Clarifications and Concerns Related to the Proposed Cost Allocation Reforms

1255. Some commenters raise concerns and request clarifications on the proposed reforms. For example, BP contends that, in the case of a multi-value project, it is unclear whether only a part of the cost of a transmission project associated with meeting changes in the resource mix and demand will be allocated under a Long-Term Regional Transmission Cost Allocation Method, as opposed to all of the costs.²⁶⁸⁸ NARUC requests that the Commission provide a mechanism for future review of cost allocation methods for Long-

Term Regional Transmission Facilities.²⁶⁸⁹

1256. Other commenters urge flexibility with respect to cost allocation methods and state involvement,²⁶⁹⁰ citing regional differences,²⁶⁹¹ to improve the likelihood of achieving consensus between affected states.²⁶⁹² OMS stresses the need for flexibility with respect to cost allocation methods to realize the NOPR's overall objectives of cost-effective regional transmission expansion.²⁶⁹³ Louisiana Commission, however, asserts that, whichever cost allocation method is adopted, it should not allow a majority to impose costs upon non-consenting states.²⁶⁹⁴

1257. Shell states that the Commission should require coastal transmission providers to explain how their Long-Term Regional Transmission Planning processes facilitate transmission planning and cost allocation for offshore wind.²⁶⁹⁵ Shell further asserts that the Commission should require all transmission providers to account for the risk of free-ridership in their OATTs, arguing that regardless of the cost allocation method applied, the Commission should ensure that first-movers are protected from free-ridership.²⁶⁹⁶

1258. Some commenters express concerns about the proposed State Agreement Process.²⁶⁹⁷ Dominion states that a practical challenge in implementing the proposed reforms will be whether having an *ex ante* cost allocation method combined with alternative proposals or some combination thereof creates an additional opportunity to debate and challenge a transmission project, resulting in delays and increased costs.²⁶⁹⁸

²⁶⁸⁹ NARUC Initial Comments at 49–50.

²⁶⁹⁰ See, e.g., Entergy Initial Comments at 29–30; Eversource Initial Comments at 29–30; Idaho Power Initial Comments at 10; NESCOE Reply Comments at 5; Pacific Northwest Utilities Initial Comments at 5–6, 11, 13.

²⁶⁹¹ See, e.g., Dominion Initial Comments at 45; Ohio Commission Federal Advocate Initial Comments at 11.

²⁶⁹² New York TOs Initial Comments at 18; see also Northwest and Intermountain Initial Comments at 18.

²⁶⁹³ OMS Initial Comments at 10.

²⁶⁹⁴ Louisiana Commission Initial Comments at 33–34.

²⁶⁹⁵ Shell Initial Comments at 17.

²⁶⁹⁶ *Id.* at 25, 28.

²⁶⁹⁷ We also address comments regarding the State Agreement Process in more detail below. See *infra* Proposals Relating to the Design and Operation of State Agreement Processes section.

²⁶⁹⁸ Dominion Initial Comments at 52.

²⁶⁷⁸ *Id.* P 302 n.509.

²⁶⁷⁹ *Id.* P 314.

²⁶⁸⁰ *Id.*

²⁶⁸¹ E.g., Breakthrough Energy Initial Comments at 6; Business Council for Sustainable Energy Initial Comments at 2; California Democratic Representatives Supplemental Comments at 2; Joint Consumer Advocates Initial Comments at 13; OMS Initial Comments at 9; Pine Gate Initial Comments at 45; WE ACT Initial Comments at 5.

²⁶⁸² Certain TDUs Initial Comments at 2, 7; City of New Orleans Council Initial Comments at 9–10; Entergy Initial Comments at 29–30; Eversource Initial Comments at 29–30; ISO–NE Initial Comments at 37; ITC Initial Comments at 28; Kentucky Commission Chair Chandler Initial Comments at 3 (citing NOPR, 179 FERC ¶ 61,028 at PP 302–303); Michigan Commission Initial

Comments at 8; NARUC Initial Comments at 51; NESCOE Initial Comments at 10; New York Commission and NYSEDA Initial Comments at 12–13; New York TOs Initial Comments at 18; North Carolina Commission and Staff Initial Comments at 15–16; NYISO Initial Comments at 48–49; OMS Initial Comments at 10; Pacific Northwest State Agencies Initial Comments at 27; Pattern Energy Initial Comments at 18; PIOs Initial Comments at 64; PJM States Initial Comments at 9–10; Resale Iowa Initial Comments at 2, 12.

²⁶⁸³ Clean Energy Buyers Initial Comments at 26–27.

²⁶⁸⁴ ITC Reply Comments at 28–29.

²⁶⁸⁵ AEP Initial Comments at 35.

²⁶⁸⁶ New Jersey Commission Initial Comments at 17, 25.

²⁶⁸⁷ SEIA Initial Comments at 24.

²⁶⁸⁸ BP Initial Comments at 12.

iii. Concerns With the Proposed Cost Allocation Reforms

1259. Some commenters generally oppose the proposed reforms. For example, Southern states that the proposal to establish a specific cost allocation process before Long-Term Regional Transmission Planning has identified actual transmission projects is too abstract to work in practice and will most likely fail to attract requisite state support.²⁶⁹⁹ Southern further asserts that the NOPR's proposed cost allocation processes do not satisfy the second prong of the Commission's FPA section 206 burden of proof to establish a just and reasonable replacement rate.²⁷⁰⁰ Pacific Northwest State Agencies oppose the option in the NOPR proposal that allows transmission providers to propose a Long-Term Regional Transmission Cost Allocation Method without involving states in its development.²⁷⁰¹

iv. Comments on Specific Aspects of the Proposed Cost Allocation Reforms

(a) Use of Existing Cost Allocation Methods for Long-Term Regional Transmission Facilities

1260. Some commenters assert that they should be able to use existing cost allocation methods for Long-Term Regional Transmission Planning, with some RTOs/ISOs²⁷⁰² and RTO/ISO stakeholders²⁷⁰³ supporting these arguments. Other commenters support the Commission permitting transmission providers to keep their existing processes that involve states in cost allocation decisions.²⁷⁰⁴ PPL supports using the existing regional cost allocation structures as a default. PPL asserts that any change to the existing cost allocation method will require an FPA section 205 filing, and interested parties, including the states, may intervene and provide testimony and evidence regarding the appropriateness of any benefit used.²⁷⁰⁵

1261. APS states that it agrees with the Commission that collaboration with Relevant State Entities is a positive approach to transmission planning, but it believes that the current cost allocation process is appropriate and should not be altered. APS, noting that the Commission has determined that additional complexities and contentiousness may result from expanding the transmission planning horizon to 20 years, argues that underlying cost causation principles will apply, and, therefore, existing cost allocation processes remain appropriate.²⁷⁰⁶

1262. Similarly, PJM contends that the need for new or expanded transmission facilities identified through Long-Term Regional Transmission Planning would fall under the reliability or market efficiency studies that it performs today, and, therefore, the Commission should permit it to use its existing *ex ante* cost allocation methods as the default cost allocation method for transmission facilities selected through Long-Term Regional Transmission Planning (absent agreement by all affected states on an alternate method). PJM states that using its existing *ex ante* approaches will provide consistency and certainty in assigning cost responsibility.²⁷⁰⁷ PJM States disagree, arguing that the Commission should not presume that existing cost allocation methods are just and reasonable without a full examination and input from retail regulators. According to PJM States, the factors that make PJM's existing cost allocation methods just and reasonable in the short term may not exist in the long term.²⁷⁰⁸

1263. PJM further requests that the Commission clarify that if a transmission provider proposes to use an existing cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning, such a proposal may not be a cause for relitigating the use of that method for transmission projects selected prior to the issuance of the final order.²⁷⁰⁹ MISO states that if existing cost allocation methods previously were determined to comply with the Order No. 1000 regional cost allocation principles, the Commission should not require another demonstration and should clarify that its proposals do not require transmission providers to modify or set

aside any existing regional cost allocation method.²⁷¹⁰ Relatedly, ITC argues that the Commission should allow for streamlined compliance plans from transmission providers that already have substantial long-range planning processes in place.²⁷¹¹

1264. PIOs proffer that having two distinct cost allocation methods can be unjust, unreasonable, and unduly discriminatory even if those methods are reasonable on their own, and that multiple cost allocation methods may create uncertainty, which the Commission has recognized can be a barrier to transmission development.²⁷¹² PIOs therefore request that the Commission: (1) require transmission providers to identify and justify differences between Long-Term Regional Transmission Planning and near-term cost allocation; (2) find that compliance filings that create opportunities for "cost allocation arbitrage" may not be approved; and (3) require transmission providers to demonstrate that their current Order No. 1000 cost allocation methods are just, reasonable, and not unduly discriminatory or preferential.²⁷¹³

1265. Dominion requests that the Commission clarify that any cost allocation method directed through this rulemaking proceeding is: (1) limited to Long-Term Regional Transmission Facilities; and (2) limited to Order No. 1000 transmission planning regions.²⁷¹⁴

1266. Clean Energy Associations request that the Commission adopt *pro forma* cost allocation provisions that would allow for regional variation where cost allocation practices are consistent with or superior to the requirements adopted in any final order. For example, Clean Energy Associations state, if vertically integrated public utilities subject to state-jurisdictional integrated resource planning can demonstrate that the state planning process appropriately identifies needs and assigns costs based on future planned generation consistent with state policies, certain requirements may not be applicable.²⁷¹⁵

(b) Comments on Whether Filing an Ex Ante Cost Allocation Method Should Be Required

1267. Some commenters support a requirement that transmission providers submit an *ex ante* cost allocation

²⁶⁹⁹ Southern Initial Comments at 6–7.

²⁷⁰⁰ *Id.* at 7 n.7.

²⁷⁰¹ Pacific Northwest State Agencies Initial Comments at 24–25.

²⁷⁰² *See, e.g.,* MISO Initial Comments at 61, 68; PJM Initial Comments at 116; SPP Initial Comments at 28–29.

²⁷⁰³ *See, e.g.,* Ameren Initial Comments at 25–27; Avangrid Initial Comments at 28; Dominion Initial Comments at 3, 45; Ohio Commission Federal Advocate Initial Comments at 2, 13; Omaha Public Power Initial Comments at 4; Pennsylvania Commission Initial Comments at 13–14; PJM States Initial Comments at 11–12; Virginia Commission Staff Initial Comments at 6.

²⁷⁰⁴ Avangrid Initial Comments at 28; Dominion Reply Comments at 11; Omaha Public Power Initial Comments at 4.

²⁷⁰⁵ PPL Initial Comments at 28–29.

²⁷⁰⁶ APS Initial Comments at 11–12.

²⁷⁰⁷ PJM Initial Comments at 115.

²⁷⁰⁸ PJM States Reply Comments at 5.

²⁷⁰⁹ PJM Initial Comments at 115 (citing NOPR, 179 FERC ¶ 61,028 at P 314).

²⁷¹⁰ MISO Initial Comments at 61.

²⁷¹¹ ITC Initial Comments at 29–30.

²⁷¹² PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 297).

²⁷¹³ *Id.* at 72.

²⁷¹⁴ Dominion Initial Comments at 49–50.

²⁷¹⁵ Clean Energy Associations Initial Comments at 36.

method or methods that would apply to all Long-Term Regional Transmission Facilities either in place of, or as a backstop for, a State Agreement Process.²⁷¹⁶ For example, Grid United suggests that the Commission mandate that transmission providers develop *ex ante* cost allocation methods for selected Long-Term Regional Transmission Facilities to remove development and financial uncertainty, provide transparency in how benefits are calculated, and ensure that cost allocation is roughly commensurate with the distribution of benefits.²⁷¹⁷

1268. MISO TOs state that *ex ante* cost allocation provides upfront certainty, explaining that MISO's *ex ante* processes work well and align with past Commission findings regarding the difficulty of supporting new construction without knowing who will pay for it and the importance of working out cost allocation up front, rather than "relitigating it" each time a transmission project is proposed.²⁷¹⁸ MISO TOs do not oppose states voluntarily agreeing to assume cost responsibility for regional transmission projects, which Commission policy already permits via participant funding, but argue that states that want to voluntarily assume cost responsibility for part or all of a transmission project should do so during the transmission planning process (*i.e.*, when considering potential transmission projects) rather than after projects have been selected, so that those approving such projects can know how costs will be allocated.²⁷¹⁹

1269. New Jersey Commission states that the Commission should not allow transmission providers to use cost allocation methods that rely solely on participant funding, such as PJM's State Agreement Approach. New Jersey Commission explains that such mechanisms are an unjust and unreasonable method for allocating the costs of holistically planned multi-driver projects and portfolios because if transmission projects can only be built if one or more states agree to assume 100% of the resulting costs, more expensive projects or portfolios that maximize net benefits to the transmission planning region will go

unbuilt, ultimately driving up system-wide costs.²⁷²⁰

1270. Illinois Commission states that *ex ante* approaches should be the primary cost allocation method and include state input and approval, and that the State Agreement Process should only be used for exceptions in which public policy goals fall outside of the scope of Long-Term Regional Transmission Planning. Illinois Commission expresses concerns because it understands the NOPR to state that transmission projects without an *ex ante* cost allocation method would not be funded unless states decide to pay for them through a State Agreement Process, which could create more expensive and siloed transmission planning that does not meet future transmission needs.²⁷²¹

1271. Many commenters express concerns about the optionality of the proposal and argue that it is necessary to have a default *ex ante* cost allocation method where agreement cannot be reached among states and to preserve FPA section 205 filing rights.²⁷²² Numerous entities support an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities to be used in the event a State Agreement Process does not result in an agreed-upon cost allocation method.²⁷²³

1272. For example, Minnesota State Entities contend that an *ex ante* process that allocates costs at least roughly proportional to benefits should be required as the default cost allocation method unless states can agree on an *ex post* cost allocation method within 90 days. Minnesota State Entities also recommend that the Commission require RTOs/ISOs to use postage stamp cost allocation as the default cost allocation method for Long-Term Regional Transmission Facilities (or portfolios of such Facilities) unless the RTO/ISO can develop an alternate cost allocation method that all affected states

agree on within 90 days following RTO/ISO approval.²⁷²⁴

1273. PIOs argue that without a default cost allocation method, transmission may be held up in stakeholder processes or by project-by-project litigation to assign costs.²⁷²⁵ PIOs further caution that the Long-Term Regional Transmission Planning framework is at risk without an *ex ante* cost allocation method because successful negotiation of a State Agreement Process for each transmission project would be unwieldy and create opportunities for free-ridership and obstructionism.²⁷²⁶ Similarly, AEE argues that relying on a State Agreement Process would not be just and reasonable and likely would stall the transmission planning and cost allocation process.²⁷²⁷ Acadia Center and CLF assert that where the Commission anticipates that states will fail to agree, it should establish the Long-Term Regional Transmission Cost Allocation Method because, otherwise, ineffective regional transmission planning processes will remain in place.²⁷²⁸

1274. SEIA argues that having a default cost allocation method will ensure that transmission that promotes public policy will be built even in the face of disagreement.²⁷²⁹ R Street states that the Commission should require schedule discipline and a default cost allocation provision for circumstances where states cannot agree, which can include an accelerated Commission-led arbitration process or Commission application of preestablished criteria.²⁷³⁰

1275. Georgia Commission asserts that, if Relevant State Entities cannot reach agreement, or if a Relevant State Entity forgoes its opportunity to participate in the State Agreement Process, there should be a default Long-Term Regional Transmission Cost Allocation Method when clear benefits have been identified for a specific transmission facility or portfolio of facilities.²⁷³¹

1276. NYISO does not object to the final order directing each transmission provider to adopt an *ex ante* cost allocation method for transmission projects selected through Long-Term

²⁷²⁰ New Jersey Commission Initial Comments at 24.

²⁷²¹ Illinois Commission Initial Comments at 16–17.

²⁷²² ACORE Supplemental Comments at 1; APPA Initial Comments at 6, 44–45; Environmental Groups Supplemental Comments at 2–3; Evergreen Action Initial Comments at 6; Georgia Commission Initial Comments at 9; ITC Initial Comments at 30–31; Massachusetts Attorney General Initial Comments at 18–21; TAPS Initial Comments at 4–5, 24–26; WIRES Initial Comments at 12–13.

²⁷²³ Evergreen Action Initial Comments at 6; Exelon Initial Comments at 24, 26; Georgia Commission Initial Comments at 8–9; ITC Initial Comments at 30–31; Massachusetts Attorney General Initial Comments at 18–20, 22–23; MISO Initial Comments at 67–68; Northwest and Intermountain Initial Comments at 18; Pine Gate Initial Comments at 7; PIOs Initial Comments at 67; TAPS Initial Comments at 4–5, 24–25; WIRES Initial Comments at 12–13.

²⁷²⁴ Minnesota State Entities Initial Comments at 6–7.

²⁷²⁵ PIOs Initial Comments at 70.

²⁷²⁶ *Id.* at 67.

²⁷²⁷ AEE Reply Comments at 15, 34.

²⁷²⁸ Acadia Center and CLF Initial Comments at 31 (citing NOPR, 179 FERC ¶ 61,028 at P 310).

²⁷²⁹ SEIA Initial Comments at 25 (citing 16 U.S.C. 824p(b)).

²⁷³⁰ R Street Initial Comments at 4, 12.

²⁷³¹ Georgia Commission Initial Comments at 9.

²⁷¹⁶ See, e.g., Grid United Initial Comments at 6; Illinois Commission Initial Comments at 16–17; Minnesota State Entities Initial Comments at 6; MISO TOs Initial Comments at 45–48; PIOs Initial Comments at 70; RMI Supplemental Comments at 2–3.

²⁷¹⁷ Grid United Initial Comments at 6.

²⁷¹⁸ MISO TOs Initial Comments at 45–48 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 557, 561; Order No. 1000, 136 FERC ¶ 61,051 at P 499).

²⁷¹⁹ *Id.* at 48–49.

Regional Transmission Planning for use when an alternative method is not identified in a process that involves the state. NYISO references, as an example, the process cited in the NOPR whereby the New York Commission plays a role in determining the cost allocation method for public policy transmission projects.²⁷³²

1277. Exelon supports requiring a default *ex ante* cost allocation method that would act as a backstop cost allocation method should the states in a transmission planning region fail to negotiate an alternative cost allocation method for a transmission project or portfolio of projects. Exelon states that failure to reach an agreement on cost allocation should not act as a barrier to needed transmission, and whatever mechanism is developed for receiving state input should not allow one or more states to thwart the goals of other states and stakeholders.²⁷³³

1278. PPL asserts that the proposal to require a Long-Term Regional Transmission Cost Allocation Method may not solve the problem of states refusing to site transmission projects where they do not agree on cost allocation, but in some transmission planning regions, it may nevertheless be helpful to have a default cost allocation method.²⁷³⁴

1279. Some commenters oppose requiring a default *ex ante* cost allocation method, whether on its own or in combination with a State Agreement Process.²⁷³⁵ For example, California Commission asserts that the Commission should not mandate an *ex ante* cost allocation method if states cannot agree to a cost allocation method by a certain date.²⁷³⁶ NRG states that the Commission should focus on voluntary cost allocation and should not use involuntary cost allocation as a substitute to participant-funded interconnection and transmission expansion.²⁷³⁷ NRG states that it would be unrealistic to expect productive negotiation among states if recourse to an *ex ante* cost allocation method is an option for any objecting state.²⁷³⁸

1280. SERTP Sponsors express concern that requiring state agreements or an *ex ante* cost allocation method

before transmission projects are identified is unworkable because regulators in the Southeast will likely insist that the projects first be identified and their benefits and costs determined before the projects are selected and cost allocation commitments are made.²⁷³⁹

SERTP Sponsors state that expecting states to accept a cost allocation for transmission projects that they do not support, based on a process they have not chosen, and to which they do not assign value or benefit for retail ratepayers, will not succeed.²⁷⁴⁰ Alabama Commission agrees with SERTP Sponsors, stating that the State Agreement Process is a more appropriate and equitable mechanism for allocating the costs of Long-Term Regional Transmission Facilities and should be the sole cost allocation method.²⁷⁴¹ Similarly, US Chamber of Commerce contends that state utility regulators would risk not adequately protecting their constituents if they were to agree to an *ex ante* cost allocation method that assessed a fixed level of costs on ratepayers regardless of the design and/or benefits of a proposed regional transmission facility.²⁷⁴²

1281. EPSA argues that because long-term transmission planning horizons introduce uncertainty risk that customers must bear, cost allocation should be voluntary to the maximum degree possible.²⁷⁴³ Louisiana Commission opposes proceeding with any transmission projects selected in Long-Term Regional Transmission Planning without the voluntary cost allocation agreement of all impacted states.²⁷⁴⁴ Mississippi Commission asserts that the Commission should not require a default *ex ante* cost allocation method because doing so would bias and undermine cost allocation negotiations between states.²⁷⁴⁵ Mississippi Commission further argues that the Commission should clarify that state agreement on cost allocation for each transmission facility, or portfolio of facilities, is what is required, not simply involvement in the stakeholder process.²⁷⁴⁶

1282. Xcel opposes a mandated *ex ante* cost allocation method, stating that the industry engaged in more effective

long-term transmission planning before Order No. 1000, and that the Commission should give transmission planning regions flexibility to identify potential solutions before identifying the cost allocation for those solutions. In addition, Xcel supports allowing transmission planning regions flexibility to tailor the benefits evaluated to the purpose of the study and project, citing MISO's experience with Long-Range Transmission Planning.²⁷⁴⁷ Similarly, Southern states that the Commission should not require an *ex ante* cost allocation process, but if it does, it should adopt the NOPR proposal to allow transmission providers to determine the appropriate benefits.²⁷⁴⁸

1283. Duke asserts that the Commission has provided no support other than pointing to Order No. 1000 as to why Long-Term Regional Transmission Facilities should have a default *ex ante* cost allocation method.²⁷⁴⁹ Duke explains that if states disagree with the need, benefits, and cost allocation determined in Commission-jurisdictional transmission planning processes, then states are likely to exercise their jurisdiction over siting and retail cost allocation to thwart development of a Long-Term Regional Transmission Facility.²⁷⁵⁰ Duke asks that the Commission clarify that transmission providers may rely solely on a State Agreement Process and are not required to adopt an *ex ante* default Long-Term Regional Transmission Cost Allocation Method.²⁷⁵¹ Duke argues that an *ex post* cost allocation method from a fully litigated Commission proceeding is a more durable solution than a default *ex ante* cost allocation, which may be similarly litigated but also delay siting approvals.²⁷⁵²

1284. NESCOE requests that the Commission confirm that if a transmission provider files a State Agreement Process, the transmission provider does not need to file an *ex ante* cost allocation method, and the time period for a state-negotiated alternate cost allocation method would not apply.²⁷⁵³

v. Other Cost Allocation Method Proposals

1285. ACEG recommends having a threshold level of voltage or capacity above which a transmission facility would receive regional cost allocation

²⁷³² NYISO Initial Comments at 49 (citing NOPR, 179 FERC ¶ 61,028 at P 300 & n.500).

²⁷³³ Exelon Initial Comments at 26.

²⁷³⁴ PPL Initial Comments at 26.

²⁷³⁵ See, e.g., Louisiana Commission Initial Comments at 30, 34; NRG Initial Comments at 6; SERTP Sponsors Initial Comments at 28; US Chamber of Commerce Initial Comments at 9–10.

²⁷³⁶ California Commission Initial Comments at 57.

²⁷³⁷ NRG Initial Comments at 6, 16.

²⁷³⁸ *Id.* at 20.

²⁷³⁹ SERTP Sponsors Initial Comments at 3, 28.

²⁷⁴⁰ *Id.* at 20.

²⁷⁴¹ Alabama Commission Initial Comments at 9.

²⁷⁴² US Chamber of Commerce Initial Comments at 9–10.

²⁷⁴³ EPSA Initial Comments at 7.

²⁷⁴⁴ Louisiana Commission Initial Comments at 17–18, 30.

²⁷⁴⁵ Mississippi Commission Initial Comments at 27; Mississippi Commission Reply Comments at 3.

²⁷⁴⁶ Mississippi Commission Initial Comments at 28.

²⁷⁴⁷ Xcel Initial Comments at 11–12.

²⁷⁴⁸ Southern Initial Comments at 27.

²⁷⁴⁹ Duke Initial Comments at 37.

²⁷⁵⁰ *Id.* at 3, 35–36.

²⁷⁵¹ *Id.* at 33.

²⁷⁵² *Id.* at 3, 36–37.

²⁷⁵³ NESCOE Initial Comments at 66–67.

because the benefits of transmission depend directly on having a robust grid capable not only of receiving diverse generation but also of withstanding extreme weather.²⁷⁵⁴

1286. Shell argues that the Commission should be open to non-traditional cost allocation methods, such as the sharing of benefits when a defined benefit/cost ratio threshold is exceeded, to achieve the goal of minimizing first-mover risk. Shell contends that sharing the cost of interconnection-related network upgrades between first movers and subsequent customers is common in the industry and points to ISO-NE, PJM, and MISO as examples of RTOs/ISOs that have revised their OATTs to attempt to address this concern.²⁷⁵⁵

1287. ELCON notes that regardless of the funding mechanism or approved cost allocation method, benefits and risks may change over time as Long-Term Scenarios are updated and needs and solutions are reassessed. Therefore, ELCON states that the three-year reexamination of Long-Term Scenarios should also review cost allocation to ensure that cost causers and willing beneficiaries continue to be assessed the costs of a transmission project over its lifetime.²⁷⁵⁶

1288. Xcel proposes that transmission planning regions rely on scenario-based studies that reflect load-serving entity inputs regarding projected generation expansion, expected types and locations of generators, and expected load. Xcel states that the load-serving entities could then adjust their resource plans in light of the resulting costs and benefits. Xcel asserts that this flexibility would result in consensus-based cost allocation tied to the transmission that load-serving entities actually need and would reduce the reluctance to participate in planning as the outcomes could be adjusted to accommodate adjustments in load-serving entity needs and expectations.²⁷⁵⁷ Xcel also argues that the Commission should make clear that it is sometimes appropriate to allocate costs to generators, and that transmission access rights allocation should follow cost allocation.²⁷⁵⁸

1289. Certain TDUs argue that the Commission should require any *ex ante* cost allocation method to follow a “beneficiary pays” approach, as opposed to the default, postage stamp load ratio share model.²⁷⁵⁹ Certain

TDUs claim that the advantages of adopting a beneficiary-pays cost allocation approach are well documented, as the circumstances appropriate for a postage stamp allocation are not necessarily present when allocating costs for Long-Term Regional Transmission Facilities.²⁷⁶⁰ R Street similarly asserts that the final order should adhere to the beneficiary-pays principle to allocate the costs of both transmission and interconnection-related network upgrades.²⁷⁶¹

1290. Cypress Creek contends that where “cost allocation would hamper the use of contingent needs as a driver for multi-value projects,” there should be a hybrid approach. Specifically, Cypress Creek suggests allocating costs up to the lesser of: (1) the cost of necessary reliability improvements and (2) the benefit-cost threshold ratio of the multi-value project to the party that needs the improvements. Cypress Creek suggests that the remaining costs be allocated according to multi-value project rules.²⁷⁶²

c. Commission Determination

1291. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to file one or more *ex ante* cost allocation methods that apply to selected Long-Term Regional Transmission Facilities. Specifically, we modify the NOPR proposal to require, instead of just permit, transmission providers in each transmission planning region to revise their OATTs to include one or more Long-Term Regional Transmission Cost Allocation Methods for Long-Term Regional Transmission Facilities that are selected. We adopt the NOPR’s proposed definition, with modification, of Long-Term Regional Transmission Cost Allocation Method as an *ex ante* regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation. In addition to this required Long-Term Regional Transmission Cost Allocation Method, we also permit transmission providers to revise their OATTs to include a State Agreement Process, if Relevant State Entities indicate that they have agreed to such a process. Any State Agreement Process that transmission providers voluntarily propose to include in their OATTs would not comply with the requirements of this final order unless

Relevant State Entities indicate to the transmission providers that Relevant State Entities have agreed to that process during the Engagement Period (which we discuss further below).²⁷⁶³

1292. While we permit transmission providers to include a State Agreement Process in their OATTs to determine cost allocation methods for selected Long-Term Regional Transmission Facilities if the process is agreed to by Relevant State Entities, it cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities. As discussed below, we find that sole reliance on a State Agreement Process to determine a cost allocation method for selected Long-Term Regional Transmission Facilities will not achieve the objectives of this final order.

Additionally, we modify the NOPR proposal to require that, if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and any other authorized entities, or if the Commission ultimately finds that the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential, then the relevant Long-Term Regional Transmission Cost Allocation Method on file would apply as a backstop. In other words, if a Long-Term Regional Transmission Facility or portfolio of such Facilities is selected but a State Agreement Process fails to result in a Commission-accepted cost allocation method for that facility or facilities, then their costs must be allocated through the Long-Term Regional Transmission Cost Allocation Method or Methods that would otherwise apply in the absence of a State Agreement Process (*i.e.*, the backstop Long-Term Regional Transmission Cost Allocation Method).²⁷⁶⁴ We clarify that, if the transmission providers have more than one Long-Term Regional Transmission Cost Allocation Method on file, then the

²⁷⁶³ We discuss the definition of Relevant State Entities below. *See infra* the Requirement that Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section.

²⁷⁶⁴ For example, transmission providers could file two Long-Term Regional Transmission Cost Allocation Methods, A and B. In this example, Method A would apply only to Long-Term Regional Transmission Facilities under 300 kV. Method B would apply to Long-Term Regional Transmission Facilities at or above 300 kV only if an agreed-upon State Agreement Process fails to result in a Commission-accepted cost allocation method. If, on compliance, transmission providers propose more than one Long-Term Regional Transmission Cost Allocation Method, they must specify to which Long-Term Regional Transmission Facilities each Long-Term Regional Transmission Cost Allocation Method applies.

²⁷⁵⁴ ACEG Initial Comments at 63.

²⁷⁵⁵ Shell Initial Comments at 25–28.

²⁷⁵⁶ ELCON Initial Comments at 19.

²⁷⁵⁷ Xcel Initial Comments at 18.

²⁷⁵⁸ *Id.* at 12–13.

²⁷⁵⁹ Certain TDUs Initial Comments at 2, 7.

²⁷⁶⁰ *Id.* at 8–9.

²⁷⁶¹ R Street Initial Comments at 4, 12.

²⁷⁶² Cypress Creek Reply Comments at 12.

method that would otherwise apply to the specific selected Long-Term Regional Transmission Facility would serve as the backstop Long-Term Regional Transmission Cost Allocation Method.

1293. We continue to find that facilitating state regulatory involvement in the cost allocation process could minimize delays and additional costs associated with state and local siting proceedings.²⁷⁶⁵ Nevertheless, we find that the requirement for transmission providers to include a Long-Term Regional Transmission Cost Allocation Method in their OATTs is necessary because, if transmission providers were to rely solely on a State Agreement Process to determine the cost allocation for Long-Term Regional Transmission Facilities and that process fails to result in agreement, there would be no cost allocation method for Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solutions to Long-Term Transmission Needs. As a result, such selected Long-Term Regional Transmission Facilities would be less likely to be developed, and the benefits that these facilities would provide would not be realized. Moreover, transmission providers would likely rely on relatively inefficient or less cost-effective transmission facilities to address the identified Long-Term Transmission Needs, or they may not even address these needs at all, leading to unjust and unreasonable Commission-jurisdictional rates. We further find that reliance solely on a State Agreement Process would suffer from the same flaws that led the Commission to require *ex ante* cost allocation for selected regional transmission facilities in Order No. 1000, as the allocation of transmission costs can be contentious and prone to litigation in multi-state transmission planning regions.²⁷⁶⁶ Requiring a Long-Term Regional Transmission Cost Allocation Method, even when transmission providers also have a State Agreement Process in effect, provides a level of certainty critical to the

development of needed Long-Term Regional Transmission Facilities.

1294. As noted above, the relevant Long-Term Regional Transmission Cost Allocation Method on file would serve as a backstop if the State Agreement Process does not result in a Commission-accepted cost allocation method for the selected Long-Term Regional Transmission Facility or portfolio of such Facilities subject to the State Agreement Process. This outcome could occur for several reasons. For instance, Relevant State Entities may not reach agreement on a cost allocation method pursuant to the terms of a State Agreement Process and the transmission providers may choose not to file any cost allocation method. In another instance, transmission providers may choose not to file a cost allocation method agreed to pursuant to a State Agreement Process and also choose not to file any alternative cost allocation method. And finally, the Commission might not accept a cost allocation method that results from a State Agreement Process and that transmission providers submit to the Commission for filing under FPA section 205 to the extent that it does not satisfy the requirement to allocate costs at least roughly commensurate with estimated benefits or is otherwise unjust or unreasonable.²⁷⁶⁷

1295. In response to NRG's and Mississippi Commission's concerns that a Long-Term Regional Transmission Cost Allocation Method could undermine productive negotiation among states if recourse to an *ex ante* cost allocation method is an option for any objecting state,²⁷⁶⁸ on balance, we find that this possibility is outweighed by the risk that Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solution to Long-Term Transmission Needs may not have an associated cost allocation method absent this requirement, and thus would be unlikely to be developed.²⁷⁶⁹ As we explain above, the

lack of a cost allocation method for selected Long-Term Regional Transmission Facilities would likely result in transmission providers relying on relatively inefficient or less cost-effective transmission facilities to address identified Long-Term Transmission Needs, or they may not even address these needs at all, leading to unjust and unreasonable Commission-jurisdictional rates. We further note that a Long-Term Regional Transmission Cost Allocation Method provides certainty that the costs of Long-Term Regional Transmission Facilities for which a State Agreement Process does not result in a Commission-approved cost allocation method will be allocated in a manner that the Commission has found to be just and reasonable and not unduly discriminatory or preferential.

1296. In response to the arguments by SERTP Sponsors, Alabama Commission, and Louisiana Commission emphasizing the importance of voluntary cost allocation among states,²⁷⁷⁰ along with Mississippi Commission's request for clarification that state agreement to a cost allocation method be required for any Long-Term Regional Transmission Facility under this final order,²⁷⁷¹ we note that Relevant State Entities will have the opportunity to provide their views on cost allocation methods during the Engagement Period, as discussed further below. Following this Engagement Period, Relevant State Entities may agree to, and ask the transmission providers to file, a State Agreement Process, which, if accepted by the Commission, would be the cost allocation process used by the transmission providers in the transmission planning region prior to the use of the relevant Long-Term Regional Transmission Cost Allocation Method as a backstop. Further, as discussed in the Proposals Relating to the Design and Operation of State Agreement Processes section below, during the Engagement Period or State Agreement Process, Relevant State Entities will have an opportunity to agree to and ask transmission providers to file a Long-Term Regional Transmission Cost Allocation Method. Thus, there are multiple opportunities for Relevant State Entities to voluntarily

Relevant State Entities and, as such, we do not require unanimous agreement of Relevant State Entities participating in the Engagement Period on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process.

²⁷⁷⁰ SERTP Sponsors Initial Comments at 3, 20, 28; Alabama Commission Initial Comments at 9; Louisiana Commission Initial Comments at 17–18, 30.

²⁷⁷¹ Mississippi Commission Initial Comments at 28.

²⁷⁶⁵ NOPR, 179 FERC ¶ 61,028 at P 301.

²⁷⁶⁶ Order No. 1000, 136 FERC ¶ 61,051 at PP 498–499; see also *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 70 (finding that the Commission reasonably balanced the benefits and claimed burdens of Order No. 1000's reforms in concluding that the requirement that each transmission provider include in its OATT a method(s) for allocating *ex ante* the costs of new regional transmission facilities “would reduce conflicts and ‘aid in the development and construction of new transmission’” and allow stakeholders “to determine *ex ante* that the benefits associated with [a particular] set of transmission facilities outweigh the costs’” (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 499, 669)).

²⁷⁶⁷ See *PPL Elec. Utils. Corp.*, 181 FERC ¶ 61,178, at P 33 (2022) (“In light of the New Jersey state law, the New Jersey [State Agreement Approach] Projects will benefit customers throughout New Jersey, and thus we find that allocating the costs of the New Jersey [State Agreement Approach] Projects on a load-ratio share basis to all New Jersey customers is roughly commensurate with the benefits provided by those projects.”) (footnote omitted).

²⁷⁶⁸ Mississippi Commission Initial Comments at 27; Mississippi Commission Reply Comments at 3; NRG Initial Comments at 20.

²⁷⁶⁹ As discussed below in the Requirement that Transmission Providers Seek Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities section, we decline to define what constitutes agreement among

negotiate a cost allocation method for Long-Term Regional Transmission Facilities.

1297. We find that US Chamber of Commerce's concern, that state utility regulators might fail to protect constituents if they were to agree to an *ex ante* cost allocation method that assessed a fixed level of costs on ratepayers regardless of the design or benefits of a proposed regional transmission facility, is misplaced.²⁷⁷² Any cost allocation method(s) that transmission providers propose, be it as a result of a State Agreement Process or a Long-Term Regional Transmission Cost Allocation Method, must allocate costs in a manner that is at least roughly commensurate with estimated benefits, as discussed further below.²⁷⁷³ For the same reasons, we disagree with EPSA's contention that, because Long-Term Regional Transmission Planning introduces uncertainty risk that customers must bear, all the relevant cost allocation methods on file should be voluntary.²⁷⁷⁴

1298. We also acknowledge Duke's concerns that a default *ex ante* cost allocation method could delay siting approvals and Xcel's concerns associated with a mandated *ex ante* cost allocation method claiming that the industry engaged more effectively in long-term transmission planning before Order No. 1000.²⁷⁷⁵ We note that another modification to the NOPR proposal that we adopt, as described below, allows State Agreement Processes to occur before, as well as up to six months after, selection of Long-Term Regional Transmission Facilities. This modification helps to address Duke's and Xcel's concerns by providing Relevant State Entities with an opportunity to agree on a cost allocation method for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities) after selection. However, we find that, even if such an agreement on a State Agreement Process cost allocation method cannot be achieved, on balance, the greater certainty that *ex ante* cost allocation methods provide to allow the development of Long-Term Regional Transmission Facilities outweighs the concerns that Duke and Xcel express.

1299. Furthermore, we find that allowing the use of a State Agreement Process in addition to a Long-Term

Regional Transmission Cost Allocation method will assist in the development of Long-Term Regional Transmission Facilities by taking into account state preferences. SEIA and New Jersey Commission support such flexibility.²⁷⁷⁶ We agree with New Jersey Commission that negotiated cost allocation methods may reduce litigation and make it easier to construct needed transmission facilities.²⁷⁷⁷ We recognize Dominion's concerns that implementing a State Agreement Process with an *ex ante* approach could lead to delays;²⁷⁷⁸ however, we find that both the backstop Long-Term Regional Transmission Cost Allocation Method, combined with a six-month limit after selection for deliberations under any State Agreement Process and the filing of any resulting cost allocation method, as detailed below, should limit such delays.

1300. Next, we adopt the NOPR proposal to apply the cost allocation reforms in this final order only to new Long-Term Regional Transmission Facilities. We find that this reform does not apply to regional reliability and economic transmission facilities that are selected pursuant to the existing Order No. 1000 regional transmission planning processes. We find, instead, that the existing Commission-accepted *ex ante* regional cost allocation methods adopted pursuant to Order No. 1000 should continue to apply to those regional reliability and economic transmission facilities. We find no basis in the record to conclude that these existing regional cost allocation methods should change, given that this final order does not alter existing regional reliability and economic transmission planning processes. We believe that this distinction between cost allocation methods for regional reliability and economic transmission projects selected under existing Order No. 1000 regional transmission planning processes and those for new Long-Term Regional Transmission Facilities selected through Long-Term Regional Transmission Planning will prevent the re-litigation of cost allocation decisions for transmission facilities that are selected prior to the effective date of this final order. In addition, we find this distinction to be consistent with our decision not to apply Long-Term Regional Transmission Cost Allocation Methods to transmission facilities other

than new Long-Term Regional Transmission Facilities.²⁷⁷⁹

1301. We disagree with PIOs that allowing different cost allocation methods to apply to different regional transmission planning processes is unjust and unreasonable.²⁷⁸⁰ We find that because Long-Term Regional Transmission Planning is a more long-term, forward-looking, and comprehensive transmission planning process than existing Order No. 1000 regional transmission planning processes, it is appropriate for transmission providers to consider, following the Engagement Period, whether different cost allocation methods should apply to selected Long-Term Regional Transmission Facilities.

1302. With respect to the potential use of existing regional cost allocation methods as Long-Term Regional Transmission Cost Allocation Methods, as well as assertions that existing cost allocation methods or current existing processes for state involvement in cost allocation decisions could be used for Long-Term Regional Transmission Planning,²⁷⁸¹ we adopt the NOPR proposal that, to the extent transmission providers believe that their existing cost allocation methods comply with the requirements adopted in this final order, they may demonstrate in their compliance filings that such methods, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of this final order. This approach is consistent with the approach that the Commission took in Order No. 1000, in which the Commission declined commenter requests to decide in the rulemaking itself whether existing cost allocation methods complied with the requirements of Order No. 1000 and instead required transmission providers to demonstrate on compliance that their existing cost allocation methods met the rulemaking's requirements.²⁷⁸²

²⁷⁷⁹ As the Commission noted in the NOPR, the Commission took a similar approach with respect to its cost allocation reforms in Order No. 1000. See NOPR, 179 FERC ¶ 61,028 at P 314 n.517 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 565).

²⁷⁸⁰ PIOs Initial Comments at 71.

²⁷⁸¹ See, e.g., Ameren Initial Comments at 25–27; APS Initial Comments at 11–12; Avangrid Initial Comments at 28; Dominion Initial Comments at 3, 45; Dominion Reply Comments at 11; MISO Initial Comments at 61, 68; NYISO Initial Comments at 9, 50; Ohio Commission Federal Advocate Initial Comments at 2, 13; Omaha Public Power Initial Comments at 4; Pennsylvania Commission Initial Comments at 13–14; PJM Initial Comments at 116; PJM States Initial Comments at 11–12; SPP Initial Comments at 28–29; Virginia Commission Staff Initial Comments at 6.

²⁷⁸² See Order No. 1000, 136 FERC ¶ 61,051 at P 565; Order No. 1000–A, 139 FERC ¶ 61,132 at P 747.

²⁷⁷² US Chamber of Commerce Initial Comments at 9–10.

²⁷⁷³ See *infra* Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities.

²⁷⁷⁴ EPSA Initial Comments at 7.

²⁷⁷⁵ Duke Initial Comments at 36; Xcel Initial Comments at 12.

²⁷⁷⁶ New Jersey Commission Initial Comments at 25; SEIA Initial Comments at 24.

²⁷⁷⁷ New Jersey Commission Initial Comments at 17.

²⁷⁷⁸ Dominion Initial Comments at 52.

1303. We disagree with PPL's contention that existing regional cost allocation methods accepted by the Commission should be considered the "default." The Commission accepted such *ex ante* regional cost allocation methods based on demonstrations of how they met the six Order No. 1000 regional cost allocation principles. We appreciate, as the Commission has recognized, that some existing regional cost allocation methods are complex, stakeholder-approved constructs and that some are specifically designed to apply to broad portfolios of transmission projects, such as MISO's regional cost allocation method for Multi-Value Projects.²⁷⁸³ However, as described above, to the extent that transmission providers propose on compliance to use an existing regional cost allocation method as a Long-Term Regional Transmission Cost Allocation Method, the transmission providers must demonstrate that such existing regional cost allocation method, as applied to Long-Term Regional Transmission Facilities, would comply with the requirements of this final order. We disagree with ITC's contention that the Commission should allow for streamlined compliance plans for transmission providers that already have long-range transmission planning processes; we reiterate that we require transmission providers to submit proposed cost allocation processes on compliance with this order so that the Commission may evaluate whether those processes comply with the requirements of this final order.

1304. BP raises a concern that it is not clear, in the case of a multi-value project, whether only a part of the cost of a transmission project associated with meeting changes in the resource mix and demand will be allocated under a Long-Term Regional Transmission Cost Allocation Method as opposed to all of the costs. With the exception of Long-Term Regional Transmission Facilities that one or more Relevant State Entities or interconnection customers agree to voluntarily fund, we clarify that all costs associated with a selected Long-Term Regional Transmission Facility must be allocated using the applicable Long-Term Regional Transmission Cost Allocation Method or Methods, or an applicable Commission-accepted cost allocation method that results from a State Agreement Process.²⁷⁸⁴

²⁷⁸³ See, e.g., *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 FERC ¶ 61,215, at P 434 (2013); *Sw. Power Pool, Inc.*, 144 FERC ¶ 61,059, at P 347 (2013).

²⁷⁸⁴ See *supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section. Moreover, in the Local Transmission Planning

1305. In response to requests that a beneficiary-pays approach be used rather than a postage stamp load ratio share model for cost allocation methods,²⁷⁸⁵ we reiterate that any cost allocation method applied to a Long-Term Regional Transmission Facility must ensure that costs are allocated in a manner that is at least roughly commensurate with the estimated benefits of the facility, consistent with cost causation and court precedent.²⁷⁸⁶ Load ratio share, which charges transmission customers in proportion to their use of the transmission system as measured by their relative share of load, is a cost allocation method that may be consistent with the beneficiary-pays approach. The Commission will evaluate whether a proposed cost allocation method allocates costs in a manner that is at least roughly commensurate with estimated benefits on a fact-specific basis, relying on the record in a given proceeding.

1306. In response to commenters that request flexibility in cost allocation,²⁷⁸⁷ we believe that the approach to cost allocation for Long-Term Regional Transmission Facilities that we adopt in this final order provides transmission providers and their stakeholders, and in particular Relevant State Entities, with the flexibility needed to address regional differences. Specifically, we find that the flexibility to submit one or more Long-Term Regional Transmission Cost Allocation Methods, as well as the flexibility to submit an additional State Agreement Process, accommodate regional differences.

1307. We decline to adopt additional requirements with respect to cost

Inputs in the Regional Transmission Planning Process section below, we provide flexibility to transmission providers to propose a cost allocation method for right-sized replacement transmission facilities.

²⁷⁸⁵ See Certain TDUs Initial Comments at 2, 7, 8–9; R Street Initial Comments at 4, 12.

²⁷⁸⁶ The cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87 (citing *Nat'l Ass'n of Regul. Util. Comm'ts v. FERC*, 475 F.3d at 1285); see also Order No. 1000, 136 FERC ¶ 61,051 at P 10 ("[T]he principles-based approach requires that all regional and interregional cost allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs. Costs may not be involuntarily allocated to entities that do not receive benefits."); *ICC v. FERC I*, 576 F.3d at 476 ("To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.").

²⁷⁸⁷ See, e.g., Entergy Initial Comments at 29–30; Eversource Initial Comments at 29–30; Idaho Power Initial Comments at 10; NESCOE Reply Comments at 5; Pacific Northwest Utilities Initial Comments at 5–6, 11, 13.

allocation that we did not propose in the NOPR, such as Shell's request to require coastal transmission providers to explain how their Long-Term Regional Transmission Planning facilitates cost allocation for offshore wind.²⁷⁸⁸ We find that the record in this proceeding does not support imposing this or other additional requirements. Regarding certain cost allocation requirements suggested by commenters,²⁷⁸⁹ including ACEG's suggestion for implementing a voltage threshold level above which a transmission facility would receive regional cost allocation,²⁷⁹⁰ we find such proposals to be beyond the scope of this proceeding. The Commission did not make such proposals in the NOPR.

2. Requirement That Transmission Providers Seek the Agreement of Relevant State Entities Regarding the Cost Allocation Method or Methods for Long-Term Regional Transmission Facilities

a. NOPR Proposal

1308. The Commission proposed to require transmission providers in each transmission planning region to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.²⁷⁹¹ The Commission proposed to require transmission providers in each transmission planning region to: (1) explain how the proposed Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof reflects the agreement of Relevant State Entities; or (2) to the extent agreement of Relevant State Entities cannot be obtained, explain the good faith efforts by the relevant transmission provider(s) to seek agreement from such entities before proposing a Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.²⁷⁹²

1309. The Commission proposed to define Relevant State Entities for purposes of the Long-Term Regional Transmission Planning cost allocation requirements as "any state entity responsible for utility regulation or siting electric transmission facilities

²⁷⁸⁸ Shell Initial Comments at 17.

²⁷⁸⁹ Cypress Creek Reply Comments at 12; ELCON Initial Comments at 19; R Street Initial Comments at 4, 12; Shell Initial Comments at 25–28; Xcel Initial Comments at 12–13, 18.

²⁷⁹⁰ ACEG Initial Comments at 63.

²⁷⁹¹ NOPR, 179 FERC ¶ 61,028 at P 303.

²⁷⁹² *Id.* P 303.

within the state or portion of a state located in the transmission planning region, including any state entity as may be designated for that purpose by the law of such state.”²⁷⁹³

1310. The Commission proposed to require transmission providers in each transmission planning region to seek to determine whether, for all or a subset of Long-Term Regional Transmission Facilities, Relevant State Entities agree to: (1) a Long-Term Regional Transmission Cost Allocation Method; (2) a State Agreement Process; (3) forgo a role in determining the cost allocation approach for Long-Term Regional Transmission Facilities; or (4) some combination thereof.²⁷⁹⁴

1311. The Commission proposed to afford transmission providers in each transmission planning region flexibility in the process by which they seek agreement from Relevant State Entities and to require transmission providers to provide the state entities with flexibility with regard to defining what constitutes “agreement” among the Relevant State Entities on the cost allocation approach for Long-Term Regional Transmission Facilities.²⁷⁹⁵ Although the Commission proposed to provide transmission providers flexibility in determining what constitutes state agreement, the Commission preliminarily found that, for each state, a single entity should be designated as the voting or representative entity to avoid confusion or over-representation by a single state in a multi-state voting process.²⁷⁹⁶

1312. Noting that the Relevant State Entities may forgo a role in determining the cost allocation approach for all or a subset of Long-Term Regional Transmission Facilities, the Commission proposed that in the event that the Relevant State Entities do so, the Commission would require transmission providers to propose a Long-Term Regional Transmission Cost Allocation Method consistent with the requirements of Order No. 1000, including the prohibition on relying on voluntary agreement among states or participant funding.²⁷⁹⁷ The Commission explained that it was not proposing to impose any requirements on states to participate in processes to establish regional cost allocation methods for Long-Term Regional Transmission Facilities.²⁷⁹⁸

b. Comments

i. State Involvement in Cost Allocation Proposals

1313. Many commenters generally support states having a role negotiating proposed cost allocation methods.²⁷⁹⁹ However, some commenters emphasize the importance of involving all stakeholders, and not just Relevant State Entities, in this reform. Clean Energy Buyers argue that the Commission should require transmission providers to allow all stakeholders (not just states) to participate in, or at least comment on, the development of the Long-Term Regional Transmission Cost Allocation Method and to recognize the importance of states and all other stakeholders.²⁸⁰⁰ Similarly, NEPOOL asserts that state involvement should not diminish the opportunity for stakeholder involvement from all market participants in the electric industry.²⁸⁰¹ APPA asserts that while coordination with state regulators in cost allocation may aid in developing beneficial and cost-effective transmission projects, the perspectives of state regulators on cost allocation should not be elevated above those of other stakeholders.²⁸⁰²

1314. Idaho Power states that the Commission should continue to allow flexibility for transmission planning regions to determine the appropriate level of state involvement.²⁸⁰³ Pacific Northwest Utilities agree, stating that mandating additional state participation

could be burdensome and problematic.²⁸⁰⁴

1315. MISO states that the Commission should not extend any state involvement that may be adopted pursuant to the final order to near-term reliability and economic regional transmission planning processes, which are beyond the scope of the final order.²⁸⁰⁵ MISO Coops state that MISO provides a stakeholder forum where states’ voices are heard, and the final order should not diminish stakeholder processes that are effective today.²⁸⁰⁶

1316. Other commenters raise concerns about increased state involvement in cost allocation decisions. For example, Vistra asserts that a prioritized role for states in cost allocation is more likely to create new challenges than ease development, and observes that it may be difficult to coordinate state interests in multi-state transmission planning regions versus single-state transmission planning regions.²⁸⁰⁷ Six Cities opposes enhanced roles for Relevant State Entities, suggesting that the proposed reforms represent neither an appropriate oversight role for states under the FPA, nor a logical extension of Order No. 890 and Order No. 1000 policies.²⁸⁰⁸

1317. ACEG and Georgia Commission agree with the Commission’s proposed definition of Relevant State Entities.²⁸⁰⁹ ACEG and Dominion also support the proposal to have a single entity designated as the voting representative for the state.²⁸¹⁰ MISO agrees that having a single entity designated for each state and/or applicable jurisdiction as the voting or representative entity for that state/jurisdiction makes sense, but notes that the City of New Orleans is an independent member of OMS separate from the Louisiana Commission and therefore may need to be considered a separate jurisdiction.²⁸¹¹ Louisiana Commission voices similar concerns.²⁸¹² North Carolina Commission and Staff state that it may be appropriate for different state entities to be designated for different roles,²⁸¹³ and Duke asserts that the Commission should clarify that within a state there

²⁷⁹⁹ See, e.g., AEP Initial Comments at 35; Ameren Initial Comments at 25; American Municipal Power Initial Comments at 12; Arizona Commission Initial Comments at 11; Clean Energy Associations Initial Comments at 35; Clean Energy Buyers Initial Comments at 28–29; Clean Energy States Initial Comments at 7; Cross Sector Representatives Supplemental Comments at 1; Duke Initial Comments at 35; ELCON Initial Comments at 17; ISO-NE Initial Comments at 2; Georgia Commission Initial Comments at 8–9; US House Republicans Supplemental Comments at 1; ITC Initial Comments at 28; Joint Consumer Advocates Initial Comments at 13; Maryland Energy Administration Initial Comments at 2; Massachusetts Attorney General Initial Comments at 19; Michigan Commission Initial Comments at 8; MISO Initial Comments at 61; NARUC Initial Comments at 45 (citing NOPR, 179 FERC ¶ 61,028 at PP 303–308), 46; New York Commission and NYSEDA Initial Comments at 1; NESCOE Initial Comments at 54; North Carolina Commission and Staff Initial Comments at 2; North Dakota Commission Initial Comments at 4; NRG Initial Comments at 6; NYISO Initial Comments at 49; OMS Initial Comments at 10; PacifiCorp and NV Energy Initial Comments at 15; PIOs Initial Comments at 64; Resale Iowa Initial Comments at 2; US Chamber of Commerce Initial Comments at 9 (citing NOPR, 179 FERC ¶ 61,028 at P 288); Virginia Commission Staff Initial Comments at 2; WIRES Initial Comments at 12.

²⁸⁰⁰ Clean Energy Buyers Initial Comments at 29.

²⁸⁰¹ NEPOOL Initial Comments at 9.

²⁸⁰² APPA Initial Comments at 42.

²⁸⁰³ Idaho Power Initial Comments at 10.

²⁸⁰⁴ Pacific Northwest Utilities Initial Comments at 13.

²⁸⁰⁵ MISO Initial Comments at 71.

²⁸⁰⁶ MISO Coops Initial Comments at 2.

²⁸⁰⁷ Vistra Initial Comments at 2, 27–28.

²⁸⁰⁸ Six Cities Initial Comments at 7.

²⁸⁰⁹ ACEG Initial Comments at 65–66; Georgia Commission Initial Comments at 8.

²⁸¹⁰ ACEG Initial Comments at 65–66; Dominion Initial Comments at 48 n.99.

²⁸¹¹ MISO Initial Comments at 66.

²⁸¹² Louisiana Commission Initial Comments at 33.

²⁸¹³ North Carolina Commission and Staff Initial Comments at 17.

²⁷⁹³ *Id.* P 304.

²⁷⁹⁴ *Id.* P 305.

²⁷⁹⁵ *Id.* P 306.

²⁷⁹⁶ *Id.* P 304.

²⁷⁹⁷ *Id.* P 307.

²⁷⁹⁸ *Id.* P 308.

may be multiple Relevant State Entities.²⁸¹⁴

1318. Some commenters generally agree with the Commission's proposed definition of Relevant State Entities but request that the definition be expanded or clarified to include self-regulated public power utilities and cooperatives.²⁸¹⁵ TAPS argues that a multi-state voting process, as proposed, could fail to represent public power and cooperatives' interests.²⁸¹⁶ NRECA contends that a more inclusive approach would be to use "relevant electric regulatory authority," which includes a state public utility commission and the governing board of a cooperative or public power utility.²⁸¹⁷ Large Public Power proposes to grant state and municipal utilities representation on a load ratio share basis.²⁸¹⁸

1319. NASUCA urges the Commission to clarify that where applicable, an approved state cost allocation process should include agreement by a state's utility consumer advocate.²⁸¹⁹ California Energy Commission recommends expanding the definition of Relevant State Entities to include any groups directly or indirectly affected by the construction of a project, such as Native American Tribes,²⁸²⁰ and NESCOE requests that the definition of Relevant State Entity be amended to accommodate individual transmission planning regions' particular approaches toward state involvement in cost allocation requirements, such as NESCOE managers designated by each New England Governor to represent that state's interests.²⁸²¹

1320. Nevada Commission requests flexibility in the term Relevant State Entity.²⁸²² New Mexico RETA urges flexibility to account for state involvement of other entities not accounted for in the definition of Relevant State Entities, including state authorities specifically designated to assist in developing new electric transmission facilities (like New Mexico RETA).²⁸²³

1321. ACEG recommends that the Commission clarify that existing

processes, such as SPP's Regional State Committee, MISO's OMS, and ISO-NE's New England States Committee, should be used to determine the Relevant State Entity for each state, unless another process is demonstrated to be superior.²⁸²⁴

1322. SERTP Sponsors assert that which Relevant State Entity or Entities would be appropriate for a particular state will be a function of state law.²⁸²⁵ Pennsylvania Commission states that the Commission's proposed definition of Relevant State Entity is imperfect and may result in multiple entities within a single state being a Relevant State Entity, given that the Commission refers to utility regulation or siting authority in the definition, but a state's legislature could have delegated this different authority among different administrative agencies.²⁸²⁶

ii. Requirement To Seek Agreement

1323. Many commenters generally support requiring transmission providers in each transmission planning region to seek the agreement of Relevant State Entities within the transmission planning region regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.²⁸²⁷

1324. Avangrid states that state input and collaboration is crucial to the transmission planning process, and that intensive state (and other stakeholder) participation and consensus-building will help to ensure that transmission will not be overbuilt.²⁸²⁸ SoCal Edison contends that without agreement among states on the respective benefits and share of related costs, the development of multi-state transmission projects will be nearly non-existent.²⁸²⁹ PPL supports transmission providers seeking

agreement with the states on cost allocation methods, as well as voluntary coordination with states, which PPL argues will make public policy projects more likely to succeed.²⁸³⁰

1325. NYISO and ISO-NE support state entities playing a role in determining the cost allocation method for transmission solutions to Long-Term Transmission Needs.²⁸³¹ ISO-NE contends that states should be responsible for determining the cost allocation mechanism for policy-based, long-term transmission facility investments because they are uniquely situated to balance the benefits and costs of transmission investments intended to advance their policy goals.²⁸³²

1326. Mississippi Commission argues that opponents of state involvement in Long-Term Regional Transmission Planning fail to recognize the existing state regulatory role in siting electricity generation, transmission, and distribution facilities.²⁸³³

1327. In addition, some commenters support the agreement of states when determining a Long-Term Regional Transmission Cost Allocation Method. City of New Orleans Council comments that it is essential that state and local regulators agree to any Long-Term Regional Transmission Cost Allocation Method to ensure that the costs borne by retail customers are just and reasonable and not unduly discriminatory or preferential.²⁸³⁴ SoCal Edison concurs on the necessity for states to reach agreement.²⁸³⁵ Southern argues that unless state regulators agree to transmission project selection and cost allocation, transmission projects that result from the Commission's proposed Long-Term Regional Transmission Planning are not likely to come to fruition.²⁸³⁶

iii. Seek Changes To, Raise Concerns About, or Oppose the Requirement To Seek Agreement

1328. Some commenters support requiring transmission providers to seek agreement with Relevant State Entities regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or a combination thereof, but propose changes to the proposal. For example,

²⁸¹⁴ Duke Initial Comments at 38–39.

²⁸¹⁵ American Municipal Power Initial Comments at 5; APPA Initial Comments at 3, 42–43 (citing 16 U.S.C. 796(7), (15)); California Municipal Utilities Initial Comments at 17; MISO Coops Initial Comments at 3–4; Six Cities Initial Comments at 10.

²⁸¹⁶ TAPS Initial Comments at 5, 26–27.

²⁸¹⁷ NRECA Initial Comments at 56–57.

²⁸¹⁸ Large Public Power Initial Comments at 41.

²⁸¹⁹ NASUCA Initial Comments at 10–11.

²⁸²⁰ California Energy Commission Initial Comments at 3.

²⁸²¹ NESCOE Initial Comments at 57.

²⁸²² Nevada Commission Initial Comments at 13.

²⁸²³ New Mexico RETA Initial Comments at 8–9 (citing NOPR 179 FERC ¶ 61,028 at P 304).

²⁸²⁴ ACEG Initial Comments at 66.

²⁸²⁵ SERTP Sponsors Initial Comments at 28–29.

²⁸²⁶ Pennsylvania Commission Initial Comments at 15.

²⁸²⁷ See, e.g., Acadia Center and CLF Initial Comments at 29–30; Avangrid Initial Comments at 28; City of New Orleans Council Initial Comments at 9; Entergy Initial Comments at 29–30; Georgia Commission Initial Comments at 8–9; ISO-NE Initial Comments at 37–38; Louisiana Commission Initial Comments at 30; Michigan Commission Initial Comments at 8; NARUC Initial Comments at 45, 47; Nebraska Commission Initial Comments at 9; NESCOE Initial Comments at 54 (citing NOPR, 179 FERC ¶ 61,028 at PP 303, 305); North Carolina Commission and Staff Initial Comments at 15–16; Ohio Commission Federal Advocate Initial Comments at 11; Pacific Northwest State Agencies Initial Comments at 27; PJM States Initial Comments at 9; SoCal Edison Initial Comments at 3; Southeast PIOs Initial Comments at 55 (citing NOPR, 179 FERC ¶ 61,028 at P 303); US Climate Alliance Initial Comments at 2; WIRES Initial Comments at 12.

²⁸²⁸ Avangrid Initial Comments at 28.

²⁸²⁹ SoCal Edison Initial Comments at 3.

²⁸³⁰ PPL Initial Comments at 29.

²⁸³¹ NYISO Initial Comments at 49; ISO-NE Initial Comments at 37.

²⁸³² ISO-NE Initial Comments at 37.

²⁸³³ Mississippi Commission Reply Comments at 5.

²⁸³⁴ City of New Orleans Council Initial Comments at 9.

²⁸³⁵ SoCal Edison Initial Comments at 3, 13.

²⁸³⁶ Southern Initial Comments at 9–10.

Kentucky Commission Chair Chandler asserts that states should not be permanently bound by their agreement on an initial cost allocation method, and that the Commission should clarify that transmission providers should continue to seek agreement from states prior to seeking Commission approval for any change to the cost allocation method filed on compliance.²⁸³⁷ Similarly, PJM States request that the Commission require transmission providers to show they sought support of retail regulators for subsequent revisions of the initial cost allocation method.²⁸³⁸ PJM States ask that the Commission also require a regular check-in with retail regulators regarding the appropriateness of any existing cost allocation method.²⁸³⁹

1329. Resale Iowa states that it is concerned that large, multi-state transmission projects may increase the number of participants to the point that agreement is difficult to achieve and suggests that multi-state organizations may provide an avenue for conveying state interests to transmission providers and reaching agreements.²⁸⁴⁰ DC and MD Offices of People's Counsel support giving state entities a "defined and expansive role" in the regional transmission selection and cost allocation processes but argue that this role must be anchored by their ability to timely agree on cost allocation.²⁸⁴¹

1330. Other commenters offered modified versions of the NOPR proposal. California Commission states that the Commission should require that transmission providers use their FPA section 205 filing rights to submit the *ex post* cost allocation method (and/or combined method) agreed on by states even if the transmission providers in a transmission planning region determine that they will propose an *ex ante* cost allocation method for the Commission's consideration.²⁸⁴²

1331. Dominion states that it may be nearly impossible to achieve state consensus in multi-state RTOs/ISOs and that if the states in a transmission planning region are unable to agree on the proper cost allocation method, the transmission providers should be able to file their own proposed cost allocation method.²⁸⁴³

1332. Some commenters oppose the proposed requirement to seek

agreement. For example, Minnesota State Entities state that the term "seeking state agreement" is too vague and may lead to disputes over the rights and responsibilities of individual states or state commissions to veto or otherwise hold up needed region-wide transmission plans. Minnesota State Entities suggest replacing the term "seeking state agreement" with "take into account" or "evaluating and incorporating" state concerns in the regional cost allocation approaches as regularly happens at MISO and other RTOs/ISOs.²⁸⁴⁴ MISO Coops state that the NOPR proposal for a transmission provider to seek agreement with Relevant State Entities is unnecessary and would be inferior to current stakeholder processes, setting up redundant and potentially conflicted processes.²⁸⁴⁵

1333. Kansas Commission questions the necessity of a requirement to seek the agreement of Relevant State Entities within a transmission planning region like SPP, where the SPP Regional State Committee has substantial influence over cost allocation.²⁸⁴⁶ PacifiCorp and NV Energy oppose a requirement for transmission providers to seek state agreement on a cost allocation method, contending that such a requirement would add complexity and significant process and time.²⁸⁴⁷ NRG states that under the proposal for transmission providers to seek the agreement of Relevant State Entities on cost allocation, customers that ultimately pay the cost of Long-Term Regional Transmission Facilities are left out of the cost allocation process. NRG suggests that the proposal be limited to transmission projects included in regional transmission plans that would not exist but for state public policy, as it is reasonable for states to fill this negotiating role as described in the NOPR.²⁸⁴⁸

1334. MISO TOs contend that MISO and MISO TOs have already afforded opportunities for states to participate in the development of cost allocation methods,²⁸⁴⁹ and argue that the NOPR requirements as drafted are unnecessary for the MISO region.²⁸⁵⁰ MISO TOs argue that the Commission should find compelling the fact that MISO, MISO TOs, and OMS all support the existing

collaborative process for cost allocation in MISO, and request that the Commission not impose changes on this process, but instead afford regional flexibility.²⁸⁵¹

1335. MISO TOs disagree with commenters that argue that the NOPR provided too much discretion and deference to transmission providers,²⁸⁵² or that the Commission should require transmission providers to add a mechanism that ensures compliance with the requirements to include Relevant State Entities in cost allocation.²⁸⁵³ MISO TOs state that these proposals are contrary to the FPA because they attempt to usurp the statutory rights of transmission providers and point to similar sentiments expressed by the Indicated PJM TOs.²⁸⁵⁴

iv. Requirements Associated With Seeking Agreement of Relevant State Entities

1336. ACEG, ACORE, and NESCOE support the NOPR proposal to require transmission providers to demonstrate their good faith efforts to seek agreement from Relevant State Entities before proposing a Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.²⁸⁵⁵ AEE states that the final order should better define what constitutes "good faith effort" to seek agreement on cost allocation from states, including the Commission's minimum expectations concerning the time that transmission providers must allow states to reach agreement, the need to hold meetings, and related topics.²⁸⁵⁶ OMS, on the other hand, urges the Commission to not require a formal process in which transmission providers must demonstrate how they sought the agreement of state entities.²⁸⁵⁷

1337. NARUC recommends that the Commission require, at a minimum, that transmission providers: (1)

²⁸⁵¹ *Id.* at 9 (citing APS Initial Comments at 10–11; MISO Initial Comments at 55–69; MISO TOs Initial Comments at 41–45; OMS Initial Comments at 10–13).

²⁸⁵² *Id.* at 4 (citing California Commission Initial Comments at 51–54).

²⁸⁵³ *Id.* at 4–5 (citing NARUC Initial Comments at 49; NESCOE Initial Comments at 16–19, 46 (requesting that the Commission either require codification of states' roles for cost allocation of long-term regional transmission facilities in OATTs or require explanation following consultation with states of a different approach)).

²⁸⁵⁴ *Id.* at 5, 8 (citing Indicated PJM TOs Initial Comments at 23).

²⁸⁵⁵ ACEG Initial Comments at 65; ACORE Initial Comments at 18 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); NESCOE Initial Comments at 59 (citing NOPR, 179 FERC ¶ 61,028 at P 308).

²⁸⁵⁶ AEE Initial Comments at 33–34.

²⁸⁵⁷ OMS Initial Comments at 11.

²⁸³⁷ Kentucky Commission Chair Chandler Initial Comments at 3.

²⁸³⁸ PJM States Initial Comments at 10.

²⁸³⁹ *Id.* at 10–11.

²⁸⁴⁰ Resale Iowa Initial Comments at 2, 12.

²⁸⁴¹ DC and MD Offices of People's Counsel Initial Comments at 37.

²⁸⁴² California Commission Initial Comments at 55–56.

²⁸⁴³ Dominion Initial Comments at 48.

²⁸⁴⁴ Minnesota State Entities Initial Comments at 7.

²⁸⁴⁵ MISO Coops Initial Comments at 4.

²⁸⁴⁶ Kansas Commission Initial Comments at 15–16.

²⁸⁴⁷ PacifiCorp and NV Energy Initial Comments at 16.

²⁸⁴⁸ NRG Initial Comments at 19.

²⁸⁴⁹ MISO TOs Initial Comments at 45.

²⁸⁵⁰ MISO TOs Reply Comments at 3.

communicate with Relevant State Entities promptly in a manner that is reasonably calculated to be received by the Relevant State Entities and (2) establish a forum for negotiation that enables robust participation from Relevant State Entities and transmission providers.²⁸⁵⁸ PacifiCorp and NV Energy urge the Commission to clarify that a transmission provider's obligation under any final order is only to provide state regulators an opportunity to participate in the process of establishing a cost allocation method, should they so choose.²⁸⁵⁹ NESCOE asserts that the Commission should require transmission providers to afford Relevant State Entities sufficient time to agree on a cost allocation approach. NESCOE advocates for the Commission to give states six months from the effective date of a final order to agree on a cost allocation method, which NESCOE argues is needed due to the complexity involved.²⁸⁶⁰

1338. Some commenters support the NOPR proposal to provide states flexibility in determining what constitutes agreement among Relevant State Entities on the cost allocation approach for Long-Term Regional Transmission Facilities.²⁸⁶¹ Alabama Commission contends that the Commission should not establish any specific timeline for negotiation to allow sufficient time for states to reach such agreement.²⁸⁶² In contrast, ACEG argues that there must be a firm time frame for any negotiations, because allowing Relevant State Entities more time to reach agreement could unnecessarily delay the process.²⁸⁶³ Likewise, Pine Gate and PIOs support requiring a firm deadline, arguing that absent such a requirement, a single state or a handful of states could significantly delay transmission development.²⁸⁶⁴

1339. While ACEG supports the NOPR proposal, ACEG cautions that this flexibility should not grant states veto power over the agreement.²⁸⁶⁵

Similarly, PJM States argue that the Commission should not require unanimity in determining an initial Long-Term Regional Transmission Cost Allocation Method, and instead, retain the proposal in the NOPR to allow states to determine how they will come to agreement on a Long-Term Regional Transmission Facility cost allocation approach.²⁸⁶⁶ New Jersey Commission further asserts that the Commission must ensure that transmission providers cannot unilaterally veto proposals that result from states' negotiations on a cost allocation approach.²⁸⁶⁷

1340. Nebraska Commission asserts that the Commission should allow RTOs/ISOs that have an existing decision-making process that includes state entity participation to continue using it, citing SPP's Regional State Committee and MISO's OMS as well-established processes developed over many years with stakeholder input. Nebraska Commission adds that providing flexibility in this process for transmission providers would be the least disruptive and most useful approach.²⁸⁶⁸ Relatedly, ACORE states that where agreements on cost allocation have already been reached with state entities for transmission projects with multiple benefits, the Commission should not require transmission providers to revisit those agreements.²⁸⁶⁹

1341. ISO-NE also supports the Commission's proposal to afford transmission providers flexibility in determining what constitutes state agreement, as well as the process by which they seek agreement from the states. ISO-NE argues that if state agreement cannot be reached, the Commission should allow the transmission planning region to develop a fallback cost allocation method for use in the event that the states agree to move forward with a long-term transmission facility to advance public policy, but do not agree on a cost allocation method. ISO-NE requests that a final order be clear that the OATT will be the means by which the states will communicate the agreed cost allocation method to the transmission provider, but the OATT should not dictate the process by which states engage to achieve consensus.²⁸⁷⁰

1342. Some commenters favor mandating what constitutes agreement

among Relevant State Entities. Pine Gate states that the Commission should establish a minimum set of criteria outlining when it will consider there to be such agreement. Pine Gate also asks for clarification as to whether unanimity is necessary for states to reach agreement on a cost allocation method.²⁸⁷¹ Similarly, AEE requests additional guidance on what it means for states to "agree" to cost allocation approaches.²⁸⁷² Shell states that an OATT mechanism that clearly delineates the process and timing for state input will facilitate the participation of Relevant States Entities. However, Shell further states, the OATT provision could provide flexibility for stakeholders to identify the relevant agency for each state as the voting entity for cost allocation decisions.²⁸⁷³

1343. Acadia Center and CLF assert that the Commission should clarify that states within a given transmission planning region need not unanimously agree on a cost allocation method and can define agreement as necessary when a majority of states in such region approve a cost allocation method for transmission facilities.²⁸⁷⁴ Acadia Center and CLF explain that such an approach is consistent with NESCOE's memorandum of understanding in ISO-NE,²⁸⁷⁵ and similarly, New England for Offshore Wind argues that the Commission should not require agreement to be unanimous among states in a multi-state transmission planning region.²⁸⁷⁶

1344. PIOs also argue that the Commission should not require that states in a particular transmission planning region unanimously approve an *ex ante* cost allocation method. PIOs assert, rather, that the Commission should allow transmission providers to adopt a cost allocation method that is otherwise just and reasonable with agreement among a majority of states. PIOs state that each RTO/ISO has an organization of states that operates as a committee and that most of these committees require a simple majority vote (for example, the SPP Regional State Committee, OPSI, and OMS) and that the experience with the RTO/ISO regional state committees can be

²⁸⁵⁸ NARUC Initial Comments at 44.

²⁸⁵⁹ PacifiCorp and NV Energy Initial Comments at 17.

²⁸⁶⁰ NESCOE Initial Comments at 60.

²⁸⁶¹ See, e.g., ACORE Initial Comments at 18 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); Georgia Commission Initial Comments at 8; Massachusetts Attorney General Initial Comments at 20 (citing NOPR, 179 FERC ¶ 61,028 at PP 306, 308); NARUC Initial Comments at 47–48 (citing NOPR, 179 FERC ¶ 61,028 at P 306); Nebraska Commission Initial Comments at 10; NESCOE Initial Comments at 58; Pacific Northwest State Agencies Initial Comments at 24–25 (citing NOPR, 179 FERC ¶ 61,028 at PP 309, 318).

²⁸⁶² Alabama Commission Initial Comments at 9.

²⁸⁶³ ACEG Initial Comments at 64–65.

²⁸⁶⁴ Pine Gate Initial Comments at 46; PIOs Initial Comments at 69–70.

²⁸⁶⁵ ACEG Initial Comments at 66.

²⁸⁶⁶ PJM States Reply Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 304, 319).

²⁸⁶⁷ New Jersey Commission Initial Comments at 17.

²⁸⁶⁸ Nebraska Commission Initial Comments at 10.

²⁸⁶⁹ ACORE Initial Comments at 18 (NOPR, 179 FERC ¶ 61,028 at P 314).

²⁸⁷⁰ ISO-NE Initial Comments at 37–38.

²⁸⁷¹ Pine Gate Initial Comments at 45–46.

²⁸⁷² AEE Initial Comments at 32–33 (citing NOPR, 179 FERC ¶ 61,028 at P 306).

²⁸⁷³ Shell Initial Comments at 16–17.

²⁸⁷⁴ Acadia Center and CLF Initial Comments at 30.

²⁸⁷⁵ *Id.* at 31 (citing Memorandum of Understanding Among ISO-NE, NEPOOL, and NESCOE, at 3, 9 (Nov. 21, 2007), https://www.iso-ne.com/static-assets/documents/regulatory/part_agree/mou_final.pdf).

²⁸⁷⁶ New England for Offshore Wind Initial Comments at 4–5.

extrapolated and applied to the non-RTO/ISO transmission planning regions as well.²⁸⁷⁷ Pattern Energy proposes that a reasonable threshold for “agreement” would be for one-half of the Relevant State Entities to agree to the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof.²⁸⁷⁸

1345. In contrast, Southeast PIOs propose that state agreement should require unanimous acceptance by the states in the relevant transmission planning region. Southeast PIOs state that in the event transmission providers are unable to achieve unanimity, the Commission could presumptively impose the cost allocation mechanism approved by a plurality of the transmission planning region’s states.²⁸⁷⁹

v. Outcome if Relevant State Entities Forgo a Role in Determining a Long-Term Regional Transmission Cost Allocation Method

1346. Some commenters support the Commission’s proposal that, in the event that states forgo a role in determining the cost allocation approach for all or a subset of Long-Term Regional Transmission Facilities, transmission providers must propose a Long-Term Regional Transmission Cost Allocation Method.²⁸⁸⁰

vi. Outcome if Relevant State Entities Fail To Reach Agreement on a Cost Allocation Method

1347. Several commenters agree with the proposal that, in the event that Relevant State Entities fail to reach an agreement on a cost allocation method, transmission providers must file a cost allocation method with the Commission.²⁸⁸¹ NARUC recommends that if Relevant State Entities are unable to reach agreement on cost allocation, the Commission should require transmission providers to file changes to their OATTs that reflect as much consensus as was reached.²⁸⁸²

1348. PIOs state that when cost allocation disputes occur, the Commission could use its authority to convene a joint board with affected states to consider issues and make

decisions.²⁸⁸³ PIOs further state that if states cannot agree to an *ex ante* cost allocation method by the compliance deadline for the final order, the Commission should institute a default cost allocation method.²⁸⁸⁴

1349. Similarly, Eversource and Vermont Electric and Vermont Transco state that when Relevant State Entities fail to agree on a cost allocation method, the Commission should establish the Long-Term Regional Transmission Cost Allocation Method.²⁸⁸⁵ To improve transparency and certainty, Clean Energy Associations state that the Commission should establish a cost allocation method upfront for situations where “state concurrence on either an *ex ante* or *ex post* approach” cannot be reached, submitting that a 90-day period would be reasonable for the Commission to determine a cost allocation method in the absence of state concurrence on either type of approach.²⁸⁸⁶

1350. In contrast, Pacific Northwest State Agencies oppose the Commission establishing a Long-Term Regional Transmission Cost Allocation Method on its own initiative.²⁸⁸⁷ NESCOE states that having the transmission provider file a cost allocation method when states cannot agree is preferable to the Commission establishing the cost allocation method. Specifically, NESCOE asserts that a more appropriate role for the Commission is to establish general principles under a final order and evaluate compliance filings made by transmission providers (or subsequent FPA section 205 proposals down the road) for adherence to those principles.²⁸⁸⁸

1351. NESCOE further suggests that if the states cannot reach agreement within the first four months after the effective date of a final order, they should be provided the opportunity to request that the Commission appoint one or more senior staff members to facilitate agreement.²⁸⁸⁹

1352. In contrast, where agreement is not reached in the established timeframe, ACEG states that the Commission should permit transmission providers to explain their good faith

efforts undertaken to seek agreement.²⁸⁹⁰

1353. Clean Energy Associations, some state legislators, and some US Senators state that the final order should provide clarity around how disagreements among states or transmission providers regarding cost allocation will be handled.²⁸⁹¹ Clean Energy Associations recommend, and Ørsted agrees, that in the absence of such agreement, the Commission should require cost allocation to track the identified and quantifiable benefits of Long-Term Regional Transmission Facilities.²⁸⁹² Senator Schumer supports providing guidance when there is no state agreement on cost allocation to prevent state vetoes of cost allocation methods and to prevent states being incentivized to free ride on transmission planning and avoid costs.²⁸⁹³

c. Commission Determination

1354. We decline to adopt the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities within the transmission planning region regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities. Instead, we modify the NOPR proposal to establish a six-month time period (Engagement Period), during which transmission providers must: (1) provide notice of the starting and end dates for the six-month time period; (2) post contact information that Relevant State Entities may use to communicate with transmission providers about any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement; and (3) provide a forum for negotiation of a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process that enables meaningful participation by Relevant State Entities.

1355. We adopt the NOPR proposal, with modification, to define Relevant State Entities as any state entity responsible for electric utility regulation or siting electric transmission facilities within the state or portion of a state located in the transmission planning

²⁸⁷⁷ PIOs Initial Comments at 66–67.

²⁸⁷⁸ Pattern Energy Initial Comments at 19.

²⁸⁷⁹ Southeast PIOs Initial Comments at 56.

²⁸⁸⁰ MISO Initial Comments at 67; NESCOE Initial Comments at 59; Pennsylvania Commission Initial Comments at 13; PIOs Initial Comments at 67.

²⁸⁸¹ ACEG Initial Comments at 64; Entergy Initial Comments at 31; Pacific Northwest State Agencies Initial Comments at 29; PacifiCorp and NV Energy Initial Comments at 16; Pattern Energy Initial Comments at 19; TAPS Initial Comments at 4, 23–24.

²⁸⁸² NARUC Initial Comments at 48–49.

²⁸⁸³ PIOs Initial Comments at 67 (citing 16 U.S.C. 824h; 18 CFR 385.1304).

²⁸⁸⁴ *Id.* at 69.

²⁸⁸⁵ Eversource Initial Comments at 30 (citing NOPR, 179 FERC ¶ 61,028 at P 310 (citation omitted)); Vermont Electric and Vermont Transco Initial Comments at 4.

²⁸⁸⁶ Clean Energy Associations Initial Comments at 36.

²⁸⁸⁷ Pacific Northwest State Agencies Initial Comments at 29.

²⁸⁸⁸ NESCOE Initial Comments at 61 (citing NOPR, 179 FERC ¶ 61,028 at P 314).

²⁸⁸⁹ *Id.* at 60.

²⁸⁹⁰ ACEG Initial Comments at 64–65.

²⁸⁹¹ Clean Energy Associations Initial Comments at 35–36 (citing NOPR, 179 FERC ¶ 61,028 at P 310); Environmental Legislators Caucus Supplemental Comments at 2; Senator Schumer Supplemental Comments at 2; US Senators Supplemental Comments at 2.

²⁸⁹² Clean Energy Associations Initial Comments at 35–36; Ørsted Initial Comments at 9.

²⁸⁹³ Senator Schumer Supplemental Comments at 2.

region, including any state entity as may be designated for that purpose by the law of such state.²⁸⁹⁴ We modify the definition to add the word “electric” before “utility regulation” to make clear that Relevant State Entities are those state agencies responsible for *electric* utility regulation, and not other types of utility regulation.

1356. Specifically, with respect to the mechanics of the Engagement Period, we require that transmission providers in each transmission planning region provide notice, such as on its OASIS page or public website, of the opportunity for any Relevant State Entity to participate in, and the starting and end dates of, the Engagement Period. The notice must include contact information for a single point of contact in the transmission planning region that the Relevant State Entities can use to communicate any agreement among Relevant State Entities on a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process, as well as a deadline for communicating such agreement.²⁸⁹⁵ Such deadline must be no earlier than the end date of the Engagement Period.

1357. We require transmission providers in each transmission planning region to provide a forum for negotiation that enables meaningful participation by Relevant State Entities during the Engagement Period, consistent with NARUC’s suggestion.²⁸⁹⁶ We require transmission providers to explain on compliance how they complied with the requirement to establish and provide notice of an Engagement Period for Relevant State Entities to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, as well as how they complied with the requirement to provide a forum for such negotiation. In response to commenters that argue that their transmission planning regions already have mechanisms for state involvement in regional transmission planning and cost allocation processes,²⁸⁹⁷ we note

that Relevant State Entities can choose to use existing mechanisms for state involvement in regional transmission planning and cost allocation processes, such as the SPP Regional State Committee and the Organization of MISO States, to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process. However, even where Relevant State Entities indicate to the transmission providers in a transmission planning region that they will use such existing mechanisms as the forum for their negotiations, transmission providers must still demonstrate on compliance that, consistent with the requirements of this final order, they provided notice of the starting and end dates for the six-month time period and posted contact information that Relevant State Entities may use to communicate with transmission providers about their proposed Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process to which Relevant State Entities have agreed, as well as a deadline for communicating such agreement.

1358. As described above, we adopt a six-month time period for the Engagement Period. While the NOPR did not propose a particular time period for the Engagement Period, we believe that the six-month time period that we adopt here balances the need to ensure that Relevant State Entities have sufficient time to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process if they choose to do so, particularly given the complexity that such negotiations may involve, with the need to ensure that an extended Engagement Period does not unduly delay the implementation of the reforms that we adopt in this final order. We appreciate Alabama Commission’s concerns about establishing a specific time period for negotiations, but we find that limiting the Engagement Period to six months is necessary to ensure that transmission providers have sufficient time to prepare their compliance filings in advance of the compliance deadlines that we establish in this final order.²⁸⁹⁸

1359. If the Relevant State Entities participating in an Engagement Period agree on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process and provide that Method or Methods and/or State Agreement Process to the transmission providers no later than the deadline for communicating agreement, which must be no earlier than the end

date of the Engagement Period, the transmission providers may file the agreed-to Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process on compliance. We note, however, that the ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers.

1360. We do not adopt the NOPR proposal that for each state, a single entity should be designated as the voting or representative entity. In light of the fact that we now require an Engagement Period, rather than mandating that transmission providers seek agreement with Relevant State Entities on the relevant cost allocation method or process, we decline to adopt a requirement that a single entity be designated for each state as the voting or representative entity. In addition, we decline to define what constitutes agreement among Relevant State Entities, how such agreement is reached, and which Relevant State Entities must reach such agreement during the Engagement Period. Instead, we leave such matters, including whether to use existing state processes as a forum for negotiations, as Nebraska Commission advocates,²⁸⁹⁹ to the Relevant State Entities participating in the Engagement Period to determine. The requirements that we establish in the final order are that transmission providers must demonstrate on compliance that they established and provided notice of an Engagement Period for Relevant State Entities to negotiate a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, as well as that they provided a forum for such negotiation.

1361. Likewise, we do not agree with commenters, like Pine Gate, that the Commission should establish a minimum set of criteria for a state agreement.²⁹⁰⁰ Instead, we find that the criteria for agreement are more appropriately determined by the Relevant State Entities participating in the Engagement Period. Whether agreement should require a majority,²⁹⁰¹ a threshold of one-half of the participating Relevant State Entities,²⁹⁰² or unanimity (Southeast PIOs)²⁹⁰³ is a

²⁸⁹⁴ See NOPR, 179 FERC ¶ 61,028 at P 304.

²⁸⁹⁵ As we discuss above in the Cost Allocation for Long-Term Regional Transmission Facilities section, Relevant State Entities must indicate that they have agreed to any State Agreement Process in order for any such process to be eligible for acceptance by the Commission in compliance with this final order. Consistent with FPA section 205, however, transmission providers have the right to not file a State Agreement Process. See *infra* Filing Rights Under the FPA section for a further discussion. See also *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) (finding that the Commission may not require utility owners to give up statutory rights under FPA section 205).

²⁸⁹⁶ NARUC Initial Comments at 44.

²⁸⁹⁷ E.g., MISO Initial Comments at 61; SPP Initial Comments at 28–30; PJM Initial Comments at 116.

²⁸⁹⁸ Alabama Commission Initial Comments at 9.

²⁸⁹⁹ Nebraska Commission Initial Comments at 10.

²⁹⁰⁰ Pine Gate Initial Comments at 45–46.

²⁹⁰¹ Acadia Center and CLF Initial Comments at 30; PIOs Initial Comments at 66–67.

²⁹⁰² Pattern Energy Initial Comments at 19.

²⁹⁰³ Southeast PIOs Initial Comments at 56.

decision for the Relevant State Entities participating in the Engagement Period. We find that this approach also addresses many of the issues commenters raised relating to the potential difficulties associated with mandating agreement on a Long-Term Regional Transmission Cost Allocation Method(s), including ACEG's concern that requiring agreement could lead to certain states holding a veto power over the agreement.²⁹⁰⁴ Moreover, we reiterate that, as discussed in the Cost Allocation Methods for Long-Term Regional Transmission Facilities section above, transmission providers must file a Long-Term Regional Transmission Cost Allocation Method on compliance with this final order; a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities.

1362. We acknowledge commenters' support of the NOPR proposal to require transmission providers to seek the agreement of Relevant State Entities regarding the relevant cost allocation method or process to be applied to Long-Term Regional Transmission Facilities, based upon the rationale that states play a critical role in transmission planning, and that facilitating their engagement in cost allocation may minimize delays and additional costs that can be associated with associated transmission siting proceedings.²⁹⁰⁵ We find that requiring an Engagement Period provides the same opportunity for robust engagement in the cost allocation process as the NOPR proposal, and thus has the potential to achieve the same important benefits, but will reduce the practical challenges associated with requiring transmission providers to seek the agreement of Relevant State Entities.²⁹⁰⁶

1363. While we agree with commenters regarding the value of an opportunity for state engagement regarding cost allocation, and accordingly adopt the Engagement Period, we do not agree that the views of state regulators regarding the appropriate cost allocation approach are dispositive.²⁹⁰⁷ Transmission providers retain the ultimate responsibility for transmission planning, and, as discussed below, they have FPA section

205 filing rights to propose tariff changes to rates, which the Commission cannot deprive them of via this final order.²⁹⁰⁸ The Commission has a statutory responsibility to review such filings to ensure that any proposed cost allocation is just and reasonable and not unduly discriminatory or preferential. Robust state engagement can valuably inform a cost allocation approach, but it cannot supplant these distinct, statutorily defined roles.

1364. We appreciate that certain commenters request to expand or clarify the NOPR's proposed definition of Relevant State Entities to include additional entities, or to otherwise allow the participation of other entities in the Engagement Period. For example, some commenters request that the definition be expanded to include Native American Tribes, self-regulated public power utilities, cooperatives, non-jurisdictional transmission providers, customer interests, state utility consumer advocates, non-traditional state agencies, and local regulatory bodies.²⁹⁰⁹ However, we decline to expand participation in the Engagement Period beyond Relevant State Entities. As discussed in the NOPR, "regional transmission facilities face significant uncertainty and risk of not reaching construction if certain stakeholders—in particular, a state regulator responsible for permitting transmission facilities—do not perceive the regional transmission facilities' value as commensurate with their costs."²⁹¹⁰ The Commission further stated, and we continue to believe, that "providing state regulators with a formal opportunity to develop a cost allocation method for [Long-Term Regional Transmission Facilities] selected through Long-Term Regional Transmission Planning could help increase stakeholder—and state—support for those facilities, which, in turn, may increase the likelihood that those facilities are sited and ultimately developed with fewer costly delays and better ensure just and reasonable

Commission-jurisdictional rates."²⁹¹¹ For the same reasons, we also do not find it necessary to allow other stakeholders to participate in the Engagement Period, as some commenters advocate.²⁹¹² In response to Nevada Commission's request for additional flexibility in the term Relevant State Entity,²⁹¹³ and NESCOE's request to amend the definition to accommodate individual transmission planning regions' particular approaches to cost allocation requirements, we find that the definition of Relevant State Entities, as amended, recognizes the important role of states while providing sufficient regional flexibility for effective Engagement Period participation.²⁹¹⁴

1365. We acknowledge SERTP Sponsors' concern that determining which Relevant State Entities would be appropriate to participate will be a function of state law,²⁹¹⁵ and, as Pennsylvania Commission points out, a state's legislature could have divided utility regulation and siting authority among different state agencies.²⁹¹⁶ In response to these concerns and Duke's clarification request,²⁹¹⁷ and as we note above, we provide flexibility on how Relevant State Entities reach agreement during the Engagement Period and decline to adopt the requirement that, for each state, a single entity should be designated as the voting or representative entity. We clarify that there may be multiple Relevant State Entities for each state, so long as each Relevant State Entity meets the definition as provided in this final order. As noted above, the definition of Relevant State Entity provides sufficient flexibility for participation in the Engagement Period.

1366. We find that the decision to modify the NOPR proposal, which would have required transmission providers to seek agreement of Relevant State Entities, to instead require transmission providers to establish a six-month Engagement Period largely moots several other reforms proposed in the NOPR. We therefore decline to adopt other proposed reforms that

²⁹⁰⁸ See, e.g., *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9 (noting that section 205 of the FPA gives utilities the right to file rates and terms for services rendered, and finding that the Commission cannot require that utility owners give up those statutory rights under FPA section 205); *infra* Filing Rights Under the FPA section.

²⁹⁰⁹ American Municipal Power Initial Comments at 5; APPA Initial Comments at 3, 42–43 (citing 16 U.S.C. 796(7), (15)); California Energy Commission Initial Comments at 3; California Municipal Utilities Initial Comments at 16–17; Large Public Power Initial Comments at 41; MISO Coops Initial Comments at 3–4; Northwest and Intermountain Initial Comments at 18; NRECA Initial Comments at 56–57; Six Cities Initial Comments at 10.

²⁹¹⁰ NOPR, 179 FERC ¶ 61,028 at P 297 (footnote omitted).

²⁹¹¹ *Id.* at P 299.

²⁹¹² See, e.g., Clean Energy Buyers Initial Comments at 29.

²⁹¹³ Nevada Commission Initial Comments at 13.

²⁹¹⁴ NESCOE Initial Comments at 57. As discussed below in the Proposals Relating to the Design and Operation of State Agreement Process section, we will permit other participants beyond Relevant State Entities to participate in the State Agreement Process, if agreed to by Relevant State Entities.

²⁹¹⁵ SERTP Sponsors Initial Comments at 28–29.

²⁹¹⁶ Pennsylvania Commission Initial Comments at 15.

²⁹¹⁷ Duke Initial Comments at 38–39.

²⁹⁰⁴ ACEG Initial Comments at 66.

²⁹⁰⁵ NOPR, 179 FERC ¶ 61,028 at P 301 (footnote omitted); see, e.g., Avangrid Initial Comments at 28; City of New Orleans Council Initial Comments at 9; SoCal Edison Initial Comments at 3, 13.

²⁹⁰⁶ See, e.g., Minnesota State Entities Initial Comments at 7 (claiming that a requirement to seek agreement could lead to disputes over the rights and responsibilities of individual states or state commissions to veto or otherwise hold up needed region-wide transmission plans).

²⁹⁰⁷ See, e.g., Southern Initial Comments at 9.

detailed the requirements associated with transmission providers seeking agreement of Relevant State Entities.

1367. We note that transmission providers' compliance with this final order is not contingent on Relevant State Entities' participation in the Engagement Period. Transmission providers' compliance with this final order is also not contingent on Relevant State Entities reaching an agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process. If Relevant State Entities fail to reach agreement on a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process, transmission providers must still file one or more Long-Term Regional Transmission Cost Allocation Methods in compliance with this final order. We acknowledge commenters' recommendations on action we should take in the event Relevant State Entities fail to reach an agreement. But we decline to convene a joint board of affected states if Relevant State Entities cannot agree, as suggested by PIOs,²⁹¹⁸ and the Commission will not establish a Long-Term Regional Transmission Cost Allocation Method in the event that Relevant State Entities fail to agree, as proposed by Eversource and Vermont Electric and Vermont Transco.²⁹¹⁹ Because this final order requires transmission providers to file a Long-Term Regional Transmission Cost Allocation Method, these additional steps are not necessary to ensure that there will be a cost allocation method for Long-Term Regional Transmission Facilities that are selected as the more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs.

1368. Furthermore, we decline to adopt NARUC's request that the Commission provide a mechanism for future review of cost allocation methods for Long-Term Regional Transmission Facilities.²⁹²⁰ This final order requires that transmission providers establish a one-time Engagement Period for purposes of compliance with this final order; transmission providers may file subsequent changes to their cost allocation methods for Long-Term Regional Transmission Facilities pursuant to their filing rights under FPA section 205, at which point parties may file comments in support of or protests to such filings. We note, however, that some RTOs/ISOs have stakeholder

processes that occur prior to making FPA section 205 filings on cost allocation, which could provide an additional opportunity for stakeholders to present their views on a proposed cost allocation method for Long-Term Regional Transmission Facilities. We decline to require future Engagement Periods beyond the initial Engagement Period but note that transmission providers may hold future Engagement Periods if they believe such periods would be beneficial.

3. Proposals Relating to the Design and Operation of State Agreement Processes

a. NOPR Proposal

1369. The Commission preliminarily found that a State Agreement Process by which one or more Relevant State Entities voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) after they are selected may be a just and reasonable approach to cost allocation for such regional transmission facilities and that the State Agreement Process could apply to all Long-Term Regional Transmission Facilities or only to a subset thereof.²⁹²¹

1370. The Commission proposed to require that if the Relevant State Entities agree on a State Agreement Process, then the transmission providers in each transmission planning region must describe in their OATTs the process by which Relevant State Entities would reach voluntary agreement pursuant to that State Agreement Process regarding the cost allocation for Long-Term Regional Transmission Facilities, including the timeline for such processes. The Commission noted that, for example, the transmission providers in each transmission planning region could specify in their OATTs the procedures by which such voluntary agreements by the Relevant State Entities may be filed with the Commission for consideration under FPA section 205. The Commission proposed to require that such procedures include a process by which Relevant State Entities would agree to funding contributions and the mechanism by which such costs would be allocated (e.g., through a *pro forma* contract).²⁹²²

b. Comments

i. Support for State Agreement Process

1371. Several commenters generally support the Commission's proposal to permit transmission providers to submit

a State Agreement Process as a Long-Term Regional Transmission Cost Allocation Method.²⁹²³ NARUC supports allowing Relevant State Entities to agree to using the State Agreement Process to commit their customers to fund all or a portion of the costs of a Long-Term Regional Transmission Facility as a means of meeting a transmission planning region's selection criteria.²⁹²⁴

1372. Mississippi Commission contends that the State Agreement Process will likely promote transmission construction because authority over transmission construction and siting rests with the states.²⁹²⁵ Mississippi Commission asserts that the State Agreement Process is particularly suited to transmission facilities that promote state policies, noting that Long-Term Regional Transmission Planning should address state laws and utility integrated resource plans that affect the resource mix, but the cost of the transmission facilities needed to address those issues must be borne by the states and utilities whose laws and integrated resource plans require those facilities.²⁹²⁶ Likewise, Ohio Commission Federal Advocate asserts that a State Agreement Process is a just and reasonable way of allocating costs for public policy projects.²⁹²⁷ Relatedly, ELCON states that the Commission should emphasize that one state's public policy goals cannot supplant the cost causation principle or be used to impose costs on customers in states that do not have the same goals.²⁹²⁸

²⁹²³ American Municipal Power Initial Comments at 12; City of New Orleans Initial Comments at 9–10; Entergy Initial Comments at 34–35; Georgia Commission Initial Comments at 8–9; ISO–NE Initial Comments at 37; ITC Initial Comments at 28–32; Louisiana Commission Initial Comments at 33; Mississippi Commission Initial Comments at 6; NARUC Initial Comments at 53–54; NESCOE Initial Comments at 62; North Carolina Commission and Staff Initial Comments at 15–16; Ohio Commission Federal Advocate Initial Comments at 12; Pacific Northwest State Agencies Initial Comments at 27; Pennsylvania Commission Initial Comments at 12–13; PIOs Initial Comments at 64; TAPS Initial Comments at 4–5, 24–26; Resale Iowa Initial Comments at 2, 12; Southern Initial Comments at 9; SERTP Sponsors Initial Comments at 28–29.

²⁹²⁴ NARUC Initial Comments at 53–54 (citing NOPR, 179 FERC ¶ 61,028 at P 252).

²⁹²⁵ Mississippi Commission Initial Comments at 22.

²⁹²⁶ Mississippi Commission Reply Comments at 3, 24 (citing Alabama Commission Initial Comments at 4; Illinois Commission at 4, 7–8).

²⁹²⁷ Ohio Commission Federal Advocate Initial Comments at 12.

²⁹²⁸ ELCON Initial Comments at 17–18. Under the cost causation principle, the cost of transmission facilities must be allocated to those who benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. See

²⁹¹⁸ PIOs Initial Comments at 67.

²⁹¹⁹ Eversource Initial Comments at 30; Vermont Electric and Vermont Transco Initial Comments at 4.

²⁹²⁰ NARUC Initial Comments at 49–50.

²⁹²¹ NOPR, 179 FERC ¶ 61,028 at P 311.

²⁹²² *Id.* P 313.

1373. Southern also notes that state support for transmission projects is crucial as the states retain primary jurisdiction over transmission siting and certification.²⁹²⁹ Southern asserts that states should generally be allowed to make transmission project selection and cost allocation decisions pursuant to the State Agreement Process after the planning is performed and specific costs and benefits are identified.²⁹³⁰ North Carolina Commission and Staff agree that the Commission should allow states to negotiate a cost allocation method after a transmission facility has been selected through Long-Term Regional Transmission Planning.²⁹³¹ Similarly, Pennsylvania Commission states that having the State Agreement Process occur after project selection will put planning in the driver's seat, and state negotiation will be centered around a transmission project already selected, which will ensure that project planning and selection run smoothly while not frustrating the fulfillment of a state's need during the state negotiation process.²⁹³²

1374. Massachusetts Attorney General states that, due to the range and complexity of benefits and the uncertainty associated with using a long transmission planning horizon, permitting states to diverge from *ex ante* cost allocation requirements for particular transmission projects or portfolios of projects may increase the likelihood that those facilities are sited and developed with fewer costly delays and will better ensure just and reasonable rates. Massachusetts Attorney General states that the potential benefits of the State Agreement Process outweigh any concerns about free ridership.²⁹³³ R Street agrees that the proposal for a State Agreement Process could reduce cost allocation and siting disputes, but asserts that states lack the jurisdiction and resources to serve an economic oversight role and thus that state participation is not a substitute for the Commission's economic oversight or for competitive mechanisms.²⁹³⁴

1375. NESCOE supports the proposal that the State Agreement Process may apply to all, or a subset of, Long-Term

Regional Transmission Facilities. NESCOE contends that, depending on the circumstances, Relevant State Entities may find it unnecessary to have the State Agreement Process apply to all such facilities, and having the flexibility to apply the State Agreement Process to a subset of facilities is a reasonable approach.²⁹³⁵

ii. Concerns and Conditions for Support Regarding State Agreement Process

1376. Some commenters qualified their support for the State Agreement Process and/or suggest that the Commission impose conditions upon the process, including those that advocated for flexibility and deference to existing efforts to incorporate state involvement.²⁹³⁶ US DOE, on behalf of its Federal power marketing administrations, notes that, to the extent that state agreements may involve the participation of Federal power marketing administrations, the process will need to accommodate the jurisdictional implications of the parties involved and that any agreements Federal power marketing administrations execute must be consistent with their statutory authorities.²⁹³⁷

1377. Entergy states its understanding that state agreements will not bind retail commissions in exercising other authorities like siting and permitting.²⁹³⁸ Likewise, Pennsylvania Commission states that any State Agreement Process cannot serve to waive or diminish the state's siting authority over transmission facilities.²⁹³⁹

1378. Mississippi Commission states that involving state regulators in cost allocation ensures that one state's policy choices are not imposed on another state's consumers without their consent and that no state should be forced to subsidize implementation of another state's laws and policies.²⁹⁴⁰ Likewise, Avangrid states that one state should not be required to fund public policies of another state, as this could derail clean energy efforts and allow states to avoid paying their fair share.²⁹⁴¹ NRG supports a role for states on transmission projects that would not

exist but for state public policy.²⁹⁴² Virginia Commission Staff avers that state entities should retain the right to assume cost responsibility for transmission projects intended to advance their public policy goals.²⁹⁴³

1379. Pennsylvania Commission argues that the terms *ex ante* and *ex post* used in the definitions of the Long-Term Regional Transmission Cost Allocation Method and State Agreement Process are vague and that instead, the Commission should include in the definitions that the Long-Term Regional Transmission Cost Allocation Method and State Agreement Process are determined either before or after a transmission facility is selected.²⁹⁴⁴

1380. Entergy asserts that the Commission should permit flexibility as to when a State Agreement Process occurs despite the NOPR's reference to the State Agreement Process as "an *ex post* cost allocation process" because in some transmission planning regions, it may be appropriate for the State Agreement Process to begin before transmission projects are selected.²⁹⁴⁵ Entergy states that any State Agreement Process should be finalized before a portfolio is submitted to the MISO Board of Directors because it will provide certainty to stakeholders as to how costs will be allocated and ensure that the MISO Board of Directors understands how the cost allocation for the portfolio is consistent with the law and capable of withstanding legal challenges.²⁹⁴⁶ Relatedly, Mississippi Commission argues that Long-Term Regional Transmission Facilities should not be presented to an RTO/ISO governing board until states have reached agreement on cost allocation.²⁹⁴⁷

1381. Similarly, MISO asserts that the *ex post* nature of the State Agreement Process renders it unsuitable as the sole cost allocation method for Long-Term Regional Transmission Facilities. As such, MISO contends, cost allocation should be available only during a defined time set forth in the OATT, after the approval of the transmission projects, to avoid delays in the competitive transmission development process. MISO further states that failure to conclude the State Agreement Process in that timeframe should result in the transmission provider reverting to its

S.C. Pub. Serv. Auth. v. FERC, 762 F.3d at 53 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 586); see also *ICC v. FERC I*, 576 F.3d at 476.

²⁹²⁹ Southern Initial Comments at 9.

²⁹³⁰ *Id.* at 27.

²⁹³¹ North Carolina Commission and Staff Initial Comments at 15–16.

²⁹³² Pennsylvania Commission Initial Comments at 12–13.

²⁹³³ Massachusetts Attorney General Initial Comments at 19 (citing NOPR, 179 FERC ¶ 61,028 at PP 299, 314).

²⁹³⁴ R Street Initial Comments at 4, 12.

²⁹³⁵ NESCOE Initial Comments at 62–63 (citing NOPR, 179 FERC ¶ 61,028 at P 311).

²⁹³⁶ *Supra* note 2923.

²⁹³⁷ US DOE Initial Comments at 50.

²⁹³⁸ Entergy Initial Comments at 29–30 (citing NOPR, 179 FERC ¶ 61,028 at PP 302–309, 314).

²⁹³⁹ Pennsylvania Commission Initial Comments at 14.

²⁹⁴⁰ Mississippi Commission Reply Comments at 2–3.

²⁹⁴¹ Avangrid Initial Comments at 29.

²⁹⁴² NRG Initial Comments at 6.

²⁹⁴³ Virginia Commission Staff Initial Comments at 6.

²⁹⁴⁴ Pennsylvania Commission Initial Comments at 14–15.

²⁹⁴⁵ Entergy Initial Comments at 34–35.

²⁹⁴⁶ *Id.* at 35.

²⁹⁴⁷ Mississippi Commission Initial Comments at 25–26.

default Long-Term Regional Transmission Cost Allocation Method. Finally, MISO asks that the Commission clarify that transmission providers can make changes to their competitive transmission development process to accommodate the State Agreement Process.²⁹⁴⁸

1382. DC and MD Offices of People's Counsel recommend that the State Agreement Process afford an opportunity for state entities to participate in transmission project evaluation and selection. They recommend this approach because of regional grid expansions that optimize the interconnection of portfolios of resources that likely result from power supply commitments made in conformity with state policies, and because state entity participation in cost allocation after a transmission project has already been selected may foreclose the consideration of state-specific benefits of grid decarbonization during project evaluation and selection.²⁹⁴⁹

1383. Alabama Commission contends that the Commission should provide for flexibility in the form and substance of any state agreement. Specifically, Alabama Commission explains that under Alabama law, it is unclear how the Alabama Commission would enter into such agreement and that its agreement may instead have to take the form of an order directed to Alabama Power.²⁹⁵⁰ SERTP Sponsors also state that the Commission should recognize the importance of flexibility in the development and structure of state agreements, agreeing that a state public service commission may not have authority to enter into binding state agreements. SERTP Sponsors offer that a state agreement for a state public service commission could be an endorsement of a voluntary participant funding agreement among its jurisdictional transmission providers.²⁹⁵¹ Southeast PIOs state that the applicable cost allocation method should account for regional preferences and adds that an *ex ante* method is likely a non-starter in the Southeast, but that a State Agreement Process has real potential.²⁹⁵²

1384. Acadia Center and CLF state that voluntary state agreements relating

to offshore wind could result in more efficient and cost-effective Long-Term Regional Transmission Facilities but request further clarity on voluntary agreements to assist states in understanding how these agreements allocate costs of transmission upgrades necessary for increased interconnection of renewable projects.²⁹⁵³ New England Systems states that the Commission should clarify that any State Agreement Process cannot increase the costs paid by a non-consenting transmission customer under an existing cost allocation method.²⁹⁵⁴ Pennsylvania Commission seeks clarification that a state that is not a party to a cost allocation agreement developed through the State Agreement Process cannot be required to pay for a selected transmission project.²⁹⁵⁵

1385. Cypress Creek states that the involvement of states in Long-Term Regional Transmission Planning is important but that a State Agreement Process should not be required.²⁹⁵⁶ MISO requests that the State Agreement Process be optional so as not to disrupt current frameworks of state collaboration or delay transmission expansion.²⁹⁵⁷ MISO further asserts that the proposed cost allocation reforms may undermine existing cost allocation methods and that the Commission should not extend any requirements regarding state involvement to near-term reliability and economic regional transmission planning processes, which are beyond the scope of the final order.²⁹⁵⁸

1386. In addition, MISO argues that there should be no requirement for unanimous agreement under the State Agreement Process, particularly if the decision to adopt it rests with Relevant State Entities.²⁹⁵⁹ MISO states that some flexibility as to what constitutes agreement of Relevant State Entities may be justified.²⁹⁶⁰ While Interwest supports increased state engagement, it argues that state entities should not be authorized to limit regional transmission plans by veto or by using unjust and unreasonable cost allocation principles that are subjective or fail to comprehensively consider benefits.²⁹⁶¹

²⁹⁵³ Acadia Center and CLF Initial Comments at 32 & n.93.

²⁹⁵⁴ New England Systems Initial Comments at 23.

²⁹⁵⁵ Pennsylvania Commission Initial Comments at 12.

²⁹⁵⁶ Cypress Creek Reply Comments at 14 (citing Clean Energy Associations Initial Comments at 34).

²⁹⁵⁷ MISO Reply Comments at 19.

²⁹⁵⁸ MISO Initial Comments at 60, 71.

²⁹⁵⁹ *Id.* at 66–67; MISO Reply Comments at 19.

²⁹⁶⁰ MISO Initial Comments at 66.

²⁹⁶¹ Interwest Initial Comments at 16.

1387. Chemistry Council contends that consultation with affected states should not give individual states the power to “hijack” the transmission planning process by rejecting necessary investments, withholding consent, or delaying the decision-making process. Chemistry Council asserts that the Commission should clarify that in requiring transmission providers to “seek agreement” from states in transmission project selection, it is not suggesting that individual states would have a veto in the process or the ability to unduly influence the timing or outcome of decision-making.²⁹⁶²

1388. Evergreen Action encourages the Commission to prohibit one state or stakeholder from vetoing transmission projects or cost allocation decisions. Evergreen Action further states that if consensus is not reached under a State Agreement Process, transmission providers should not extend the time allotted to reach agreement, because this would allow individual parties to delay the approval of needed transmission and remove the time pressure on Relevant State Entities to reach agreement. Evergreen Action avers that instead transmission providers should simply explain that they conducted a good-faith effort to reach agreement.²⁹⁶³

1389. SEIA also urges the Commission to limit the opportunity for any single state to veto a transmission line and to use its backstop authority under section 216 of the FPA if parties are unable to reach an agreement and a relevant state authority withholds or denies the siting permit for the transmission facility.²⁹⁶⁴ US Climate Alliance agrees that the process should encourage states to engage in good faith discussions to realize common benefits without over-leveraging a single state's power over a regional transmission project.²⁹⁶⁵ National Grid suggests that if states cannot agree within a reasonable period on a proposed cost allocation method for a specific set of Long-Term Regional Transmission Facilities, then the transmission providers or developers building those facilities should be required to file a proposed cost allocation method for them.²⁹⁶⁶ In contrast, NRG states that without recourse to an *ex ante* cost allocation method, negotiations under the State Agreement Process would be more productive.²⁹⁶⁷

²⁹⁶² Chemistry Council Initial Comments at 7.

²⁹⁶³ Evergreen Action Initial Comments at 6.

²⁹⁶⁴ SEIA Initial Comments at 25 (citing 16 U.S.C. 824p(b)).

²⁹⁶⁵ US Climate Alliance Initial Comments at 2.

²⁹⁶⁶ National Grid Initial Comments at 25–26.

²⁹⁶⁷ NRG Initial Comments at 20–21.

²⁹⁴⁸ MISO Initial Comments at 69.

²⁹⁴⁹ DC and MD Offices of People's Counsel Initial Comments at 37–38.

²⁹⁵⁰ Alabama Commission Initial Comments at 10 n.8.

²⁹⁵¹ SERTP Sponsors Initial Comments at 28–29.

²⁹⁵² Southeast PIOs Reply Comments at 22–23 (citing Dominion Initial Comments at 50–52; Duke Initial Comments at 35–37; SERTP Sponsors Initial Comments at 28–29; Southern Initial Comments at 27–28).

1390. California Commission is concerned that the NOPR proposal grants too much deference to transmission providers and will enable them to exercise veto power over state-negotiated cost allocation agreements.²⁹⁶⁸ California Municipal Utilities and TANC ask that the Commission require that local regulatory authorities be included in any State Agreement Process, stating that the jurisdictional implications of the NOPR proposal are unclear given that public power entities are not generally subject to the jurisdiction of their respective state commissions.²⁹⁶⁹ Mississippi Commission and Northwest and Intermountain support expanding a State Agreement Process to include non-jurisdictional utilities.²⁹⁷⁰ California Municipal Utilities further assert that, if any state body is created to examine transmission planning issues, it must include public power entities.²⁹⁷¹ Because the written comment process is not sufficient to facilitate a constructive dialogue, California Municipal Utilities urge the Commission to refrain from adopting any specific proposals from the NOPR until such a dialogue between states and public power can occur.²⁹⁷²

1391. Some commenters are concerned about the reliance on voluntary contributions that may occur under a State Agreement Process. Clean Energy Associations states that while *ex post* frameworks that rely on voluntary contributions from states or interconnection customers may be useful in some circumstances, they may not appropriately acknowledge system-wide benefits of high-voltage elements, which under the State Agreement Process could be treated as benefitting only a single state. According to Clean Energy Associations, courts have found such an outcome improper, and this approach is unlikely to yield agreement in practice.²⁹⁷³ Likewise, Cypress Creek asserts that any *ex post* cost allocation method should acknowledge widespread benefits without imposing new restrictions.²⁹⁷⁴ AEE contends that the

State Agreement Process, and more broadly the requirement to seek agreement of states regarding applicable cost allocation methods, should not substitute for allocating costs to all beneficiaries based on the broad set of benefits that regional transmission investment can provide. AEE states that reliance on voluntary state agreement should allow all states to consider the broad benefits that additional regional transmission facilities provide and the legal obligation to allocate costs commensurate with benefits received.²⁹⁷⁵

1392. DC and MD Offices of People's Counsel suggest that cost allocation should be based on the NOPR's defined benefits to all appropriate beneficiaries, with a further cost allocation to states that opt to submit additional transmission needs. DC and MD Offices of People's Counsel state that this approach would be more expansive than the existing State Agreement Approach in PJM because it would allow for a parallel default allocation of costs to the state entities not opting in, but narrowed to align with the NOPR-listed benefits, and a second round of cost allocation after the participating Relevant State Entities have shared costs aligned with the broader measure of benefits, which would help avoid the free-rider problem.²⁹⁷⁶

1393. Avangrid states that a fair approach to cost allocation under the State Agreement Process could be payments and benefits based on tiers, providing the example that if states A and B have public policies supported by new transmission while state C does not, then only states A and B should pay the cost of public policy benefits while all three states should be responsible for the cost associated with economic and reliability benefits.²⁹⁷⁷ Similarly, PIOs assert that under the State Agreement Process, costs identified in Long-Term Regional Transmission Planning should first be allocated to transmission customers as the primary beneficiaries, and then states and/or interconnection customers can voluntarily accept cost allocation for the alternative or expanded transmission projects compared to projects identified in the regional base case plan.²⁹⁷⁸

1394. AEE asks that the Commission provide additional guardrails for the State Agreement Process to ensure that there are not transmission project

delays.²⁹⁷⁹ According to AEE, the Commission must ensure that excessive reliance on the State Agreement Process does not exacerbate free-ridership problems where states outside of those agreements receive benefits from transmission projects developed under state agreements but are not expected to contribute to the costs.²⁹⁸⁰

1395. Duke argues that any tariff language memorializing the State Agreement Process must specify that the transmission provider "will not be obligated to accept cost allocation methods proposed by Relevant State Entities."²⁹⁸¹ Duke also asks that the Commission clarify that if transmission providers only adopt a State Agreement Process, and that fails, then transmission providers are free to make an FPA section 205 filing to implement an *ex post* cost allocation method.²⁹⁸² Further, Duke asks that the Commission clarify that the regulatory text's reference to "transmission provider" is "the entity with the section 205 rights to initiate rate changes, which depending upon the applicable governance and OATT structures, may be the transmission owner, but not the transmission provider."²⁹⁸³

1396. Some commenters support requiring state involvement in cost allocation. For example, New York Commission and NYSEDA state that state-led cost allocation should be a requirement in any final order and that cost allocation for public policy-driven transmission projects should be subject to state review and approval.²⁹⁸⁴ Pacific Northwest State Agencies support requiring transmission providers to have an *ex post* State Agreement Process as an alternative to an *ex ante* cost allocation method.²⁹⁸⁵

iii. Opposition to a State Agreement Process

1397. Some commenters express concern that a State Agreement Process may not be a just and reasonable approach to cost allocation for regional transmission facilities.²⁹⁸⁶ R Street contends that states do not represent all beneficiaries who may be assigned costs and, as such, cost allocation predicated on state agreement may be unjust and

²⁹⁶⁸ California Commission Initial Comments at 51, 54–55 (citing NOPR, 179 FERC ¶ 61,028 at P 319).

²⁹⁶⁹ California Municipal Utilities Initial Comments at 16; TANC Initial Comments at 17.

²⁹⁷⁰ Mississippi Commission Reply Comments at 5 (citing MISO Coops Initial Comments at 3–4); Northwest and Intermountain Initial Comments at 18.

²⁹⁷¹ California Municipal Utilities Initial Comments at 4.

²⁹⁷² California Municipal Utilities Reply Comments at 10.

²⁹⁷³ Clean Energy Associations Initial Comments at 35 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d at 1261).

²⁹⁷⁴ Cypress Creek Reply Comments at 14.

²⁹⁷⁵ AEE Reply Comments at 15–16.

²⁹⁷⁶ DC and MD Offices of People's Counsel Initial Comments at 38–39 (citing *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024).

²⁹⁷⁷ Avangrid Initial Comments at 29–30.

²⁹⁷⁸ PIOs Initial Comments at 68 (citing NOPR, 179 FERC ¶ 61,028 at PP 75–76).

²⁹⁷⁹ AEE Initial Comments at 33 (citing NOPR, 179 FERC ¶ 61,028 at PP 311–318).

²⁹⁸⁰ *Id.*

²⁹⁸¹ Duke Initial Comments at 39–40.

²⁹⁸² *Id.* at 3.

²⁹⁸³ *Id.* at 40 n.77.

²⁹⁸⁴ New York Commission and NYSEDA Initial Comments at 12, 14.

²⁹⁸⁵ Pacific Northwest State Agencies Initial Comments at 27.

²⁹⁸⁶ APPA Initial Comments at 40, 44; MISO Coops Initial Comments at 2; R Street Initial Comments at 12.

unreasonable. R Street states, however, that a state advisory or partial approval mechanism could be structured to give state agreement pivotal influence over cost allocation decisions.²⁹⁸⁷

1398. APPA claims that the proposed State Agreement Process is unworkable and creates significant uncertainty and potential for litigation.²⁹⁸⁸ APPA further asserts that providing state regulators with an exclusive role in determining cost allocation methods will not likely result in a broad consensus across stakeholders.²⁹⁸⁹ MISO Coops add that it is unjust and unreasonable, arguing that, because cooperatives are often not jurisdictional to a state entity, it is unclear how cooperatives would be represented. Thus, MISO Coops state, the State Agreement Process would reduce the involvement of cooperatives in regional transmission planning processes while granting states authority over entities outside their jurisdiction. MISO Coops further state that the proposed State Agreement Process is unnecessary because the current MISO stakeholder process is superior.²⁹⁹⁰ MISO TOs oppose any provision that would mandate a State Agreement Process.²⁹⁹¹

iv. Requirement To Document State Agreement Process in OATT

1399. Some commenters agree with the NOPR proposal that for any State Agreement Process, transmission providers in each transmission planning region must detail in their OATTs the process by which Relevant State Entities would reach agreement regarding the cost allocation for Long-Term Regional Transmission Facilities pursuant to the State Agreement Process, including the timeline for such processes.²⁹⁹² NESCOE contends that if the State Agreement Process is chosen by the Relevant State Entities, the details of how the state entities would agree to funding contributions and the mechanisms by which the costs would be allocated should be mostly informed by states and then filed by the transmission provider.²⁹⁹³ NESCOE suggests that the Commission be open to variations in the State Agreement Process as long as the details of all those variations are filed with the Commission.²⁹⁹⁴

1400. Northwest and Intermountain state that the Commission should review negotiated cost allocation methods.²⁹⁹⁵ Likewise, APPA argues that the Commission should require that any state agreement to voluntarily fund transmission facilities must be filed with the Commission for approval, in order to afford parties the opportunity to comment.²⁹⁹⁶

1401. Some commenters disagree that the Commission should require transmission providers in each transmission planning region to detail such processes in their OATTs. For example, OMS argues that it is unnecessary for transmission providers to explicitly define such a process in their OATTs.²⁹⁹⁷ Mississippi Commission argues that the Commission should clarify that OATT language describing the process by which states reach agreement should not be prescriptive or limiting and, instead, should provide only a general discussion of a process.²⁹⁹⁸

c. Commission Determination

1402. We adopt the NOPR proposal, with modification, to allow, but not require, transmission providers in each transmission planning region to adopt a State Agreement Process for allocating the costs of all, or a subset of, Long-Term Regional Transmission Facilities. We also modify the definition of State Agreement Process to be a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation. We note that Relevant State Entities have the option to include the participation of other entities in a State Agreement Process.

1403. As discussed in more detail below, we also adopt the NOPR proposal to require transmission providers that choose to file any State Agreement Process agreed to by Relevant State Entities to describe the State Agreement Process in proposed tariff provisions in their OATTs. The tariff provisions must describe key information on how the State Agreement Process will result in a cost allocation being filed, including which entities can participate in the State Agreement Process; what constitutes an

agreement on cost allocation in that process; how agreement is communicated to the transmission providers; and the circumstances under which, or the information necessary for, transmission providers to file or to consider filing the agreed cost allocation method.²⁹⁹⁹

1404. Consistent with the NOPR, we find that a State Agreement Process can be a just and reasonable approach to allocate costs for Long-Term Regional Transmission Facilities. We also find that State Agreement Processes may apply to all Long-Term Regional Transmission Facilities or only to a subset thereof.³⁰⁰⁰ We believe that allowing State Agreement Processes will help to address some commenters' request for a stronger state role in the cost allocation of Long-Term Regional Transmission Facilities,³⁰⁰¹ increasing the likelihood that more efficient or cost-effective Long-Term Regional Transmission Facilities that are selected will be developed. However, as discussed in Cost Allocation Methods for Long-Term Regional Transmission Facilities section above, a State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities; we also require transmission providers to file a Long-Term Regional Transmission Cost Allocation Method on compliance with this final order so that if the State Agreement Process on file fails to result in a Commission-accepted cost allocation method, there will still be a cost allocation method for Long-Term Regional Transmission Facilities that are selected as the more efficient or cost-effective regional transmission solutions to Long-Term Transmission Needs.

1405. We note that this final order provides significant flexibility to Relevant State Entities with respect to the design and implementation of any State Agreement Process. Such flexibility includes, for example, the opportunity to decide which entities beyond Relevant State Entities will participate in the State Agreement Process, the ability to identify the Long-Term Regional Transmission Facilities to which the State Agreement Process will apply, and how agreement as to a cost allocation method will be reached.

1406. We further expand these flexibilities by modifying the NOPR proposal to clarify that a State Agreement Process can occur either before or no later than six months after

²⁹⁸⁷ R Street Initial Comments at 12.

²⁹⁸⁸ APPA Initial Comments at 40, 44.

²⁹⁸⁹ *Id.* at 43.

²⁹⁹⁰ MISO Coops Initial Comments at 2–4.

²⁹⁹¹ MISO TOs Initial Comments at 5, 46.

²⁹⁹² Louisiana Commission Initial Comments at 33; NESCOE Initial Comments at 63; SDG&E Initial Comments at 5; TAPS Initial Comments at 24.

²⁹⁹³ NESCOE Initial Comments at 63.

²⁹⁹⁴ NESCOE Reply Comments at 5.

²⁹⁹⁵ Northwest and Intermountain Initial Comments at 18–19.

²⁹⁹⁶ APPA Initial Comments at 34–35.

²⁹⁹⁷ OMS Initial Comments at 12–13.

²⁹⁹⁸ Mississippi Commission Initial Comments at 27–28.

²⁹⁹⁹ NOPR, 179 FERC ¶ 61,028 at P 313.

³⁰⁰⁰ *Id.* P 311.

³⁰⁰¹ See, e.g., Mississippi Commission Initial Comments at 22; Southern Initial Comments at 9.

a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is selected. We believe that providing flexibility for a State Agreement Process to occur (and thus for the Relevant State Entities to agree on a cost allocation method) before Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) are selected will increase the likelihood that Regional State Entities support their selection and future development. We note that this flexibility with regard to the timing of a State Agreement Process should accommodate the timing preferences expressed by certain commenters.³⁰⁰² However, we also require that any State Agreement Process must be completed, *i.e.*, any resulting cost allocation method must be filed with the Commission, no later than six months after selection of the applicable Long-Term Regional Transmission Facility (or portfolio of such Facilities).³⁰⁰³

1407. As the Commission has previously noted, agreements outside of the context of Order No. 1000 regional cost allocation methods, such as PJM's State Agreement Approach, can result in cost allocations that are just and reasonable.³⁰⁰⁴ We also note that Order No. 1000 allows market participants to negotiate alternative cost sharing arrangements voluntarily and separately from the regional cost allocation method or set of methods, and nothing in this final order would prohibit such voluntary cost sharing arrangements.³⁰⁰⁵ Moreover, as the Commission noted in the NOPR, the Commission recently issued a Policy Statement addressing state efforts to develop transmission facilities through voluntary agreements to plan and pay for those facilities, recognizing that such voluntary agreements may allow state-prioritized transmission facilities to be planned and built more quickly than would comparable facilities that are through the regional transmission planning process.³⁰⁰⁶ Further, while we require in this final order that transmission providers have a Long-Term Regional Transmission Cost Allocation Method for selected Long-Term Regional Transmission Facilities, we note that

nothing in this final order limits a transmission provider's ability to propose under FPA section 205 any other cost allocation methods in addition to the cost allocation method used to comply with this final order.

1408. In the NOPR, the Commission noted that it has previously expressed concern regarding participant funding, which shares some similarities with State Agreement Processes.³⁰⁰⁷ In Order No. 1000, for example, the Commission explained that reliance on participant funding as a regional cost allocation method "increases the incentive of any individual beneficiary to defer investment in the hopes that other beneficiaries will value a transmission project enough to fund its development" and would therefore not comply with the Order No. 1000 regional cost allocation principles.³⁰⁰⁸ The Commission declined to allow transmission providers to file participant funding cost allocation approaches as their *ex ante* cost allocation methods for selected regional transmission facilities.³⁰⁰⁹ We take a similar approach here: we require transmission providers to include in their OATTs one or more Long-Term Regional Transmission Cost Allocation Methods (*i.e.*, their *ex ante* cost allocation method(s)) that can be used to allocate the costs of selected Long-Term Regional Transmission Facilities. As in Order No. 1000, the Long-Term Regional Transmission Cost Allocation Method cannot be participant funding. We find that requiring a Long-Term Regional Transmission Cost Allocation Method or Methods that will apply to any selected Long-Term Regional Transmission Facility reduces the incentive for project beneficiaries to defer investment.

1409. However, in addition to requiring a Long-Term Regional Transmission Cost Allocation Method, we also provide flexibility to Relevant State Entities to agree to a State Agreement Process, which transmission providers may choose to file as part of their compliance filings. We conclude that allowing such an approach as an option is reasonable despite the Commission's previously-stated concerns with participant funding, because a State Agreement Process is an established process, agreed to in

advance and described in transmission providers' OATTs, through which Relevant State Entities agree to a cost allocation method. We find that, for the purposes of Long-Term Regional Transmission Planning, a State Agreement Process will help to facilitate agreement and cooperation among Relevant State Entities. We find that this approach balances the need for the certainty with respect to cost allocation provided by an *ex ante* cost allocation method with the flexibility of allowing for a State Agreement Process-derived cost allocation method for selected Long-Term Regional Transmission Facilities (or portfolios of such Facilities). We emphasize, however, that the Commission will still review any cost allocation method that results from a State Agreement Process to ensure that it is just and reasonable and not unduly discriminatory or preferential, and that it allocates costs in a manner that is at least roughly commensurate with estimated benefits.

1410. In the context of Long-Term Regional Transmission Planning, we believe that allowing the use of State Agreement Processes to derive a cost allocation method for selected Long-Term Regional Transmission Facilities will provide states with an opportunity to be more involved in cost allocation for these transmission facilities, leading to an increased likelihood that such facilities are developed. Specifically, the engagement of Relevant State Entities in cost allocation discussions could reduce instances in which a Long-Term Regional Transmission Facility is selected and has an established *ex ante* cost allocation method that applies to it, but ultimately is not developed because it does not receive a necessary state approval.³⁰¹⁰ We also find that a State Agreement Process could provide greater confidence to Relevant State Entities that customers are receiving benefits in a manner that is at least roughly commensurate with the costs they are paying for Long-Term Regional Transmission Facilities.

1411. We acknowledge commenters' concerns that a State Agreement Process could present free-ridership issues.³⁰¹¹ For example, there could be free-ridership concerns if the Relevant State Entities in certain states agree to be allocated all of the costs for a particular Long-Term Regional Transmission Facility but that facility also benefits other entities in other states that are not similarly allocated costs under the cost allocation method arrived at through the State Agreement Process. However, we

³⁰⁰² See, *e.g.*, Pennsylvania Commission Initial Comments at 12–13; Entergy Initial Comments at 35.

³⁰⁰³ We discuss this duration requirement *infra* at P 1413.

³⁰⁰⁴ See *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 142; *PJM Interconnection, L.L.C.*, 179 FERC ¶ 61,024 at PP 40–43.

³⁰⁰⁵ See Order No. 1000, 136 FERC ¶ 61,051 at P 561.

³⁰⁰⁶ NOPR, 179 FERC ¶ 61,028 at P 300 (citing *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at PP 2, 6).

³⁰⁰⁷ See *id.* P 316 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 723).

³⁰⁰⁸ *Id.* P 316 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 723). Under a participant funding approach to cost allocation, the costs of a transmission facility are allocated only to those entities that volunteer to bear those costs. *Id.* P 316 n.519 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 486 n.375).

³⁰⁰⁹ See Order No. 1000, 136 FERC ¶ 61,051 at P 723.

³⁰¹⁰ NOPR, 179 FERC ¶ 61,028 at P 314.

³⁰¹¹ See, *e.g.*, R Street Initial Comments at 12.

continue to find that allowing a State Agreement Process for Long-Term Regional Transmission Facilities, where agreed to by the Relevant State Entities, appropriately balances free-ridership concerns with the benefit of greater state involvement in determining the cost allocation method for Long-Term Regional Transmission Facilities and the increased likelihood that such facilities will be built.³⁰¹² Additionally, nothing in this final order changes the requirements for all cost allocation methods, including those that result from a State Agreement Process, to allocate costs in a manner that is at least roughly commensurate with estimated benefits, and we believe that Commission review to ensure that cost allocation methods meet that standard will act to prevent free ridership.

1412. As noted above, there is significant commenter support for a State Agreement Process, particularly among state entities. In addition, we believe that many of the concerns expressed about the State Agreement Process proposal appear to be based on a lack of sufficient explanation in the NOPR regarding the implications of the proposal, which we clarify here. Contrary to some comments, we do not require transmission providers to adopt a State Agreement Process; rather, as discussed in the Filing Rights Under the FPA section, transmission providers may choose to file a State Agreement Process for all, or a subset of, Long-Term Regional Transmission Facilities on compliance. Also, we neither impose an obligation on a state or states to agree to a cost allocation method for Long-Term Regional Transmission Facilities, nor do we create any obligation that transmission providers file a cost allocation method resulting from a State Agreement Process, unless the transmission providers had clearly indicated assent to do so in their OATTs.³⁰¹³ As we note in the discussion of transmission provider filing rights in the Filing Rights Under the FPA section below, we believe that the applicable statute and precedent require us to preserve the right of transmission providers to file with the Commission their preferred cost allocation method for Long-Term Regional Transmission Facilities to

comply with the requirements of this final order.

1413. However, as noted earlier in this section, we establish a deadline of no later than six months after selection of a Long-Term Regional Transmission Facility (or portfolio of such Facilities) by which transmission providers must file any cost allocation method that results from a State Agreement Process. We believe that the State Agreement Process can only be effective if there is a limit on the time to reach agreement before defaulting to the Long-Term Regional Transmission Cost Allocation Method that we require transmission providers include in their OATTs. The lack of such a deadline could cause delay and increase uncertainty regarding selected Long-Term Regional Transmission Facilities. In addition, we agree with some commenters³⁰¹⁴ that a deadline, bolstered by a default Long-Term Regional Transmission Cost Allocation Method, may increase the incentive for Relevant State Entities to reach agreement on cost allocation for a particular Long-Term Regional Transmission Facility through a State Agreement Process.

1414. We find that six months is a reasonable period for State Agreement Process deliberations on a cost allocation method because it balances the need for adequate time for negotiations with transmission providers' need for finality in their Long-Term Regional Transmission Planning. While few commenters directly addressed the time period for negotiation under a State Agreement Process for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities), many commenters favored this duration for the NOPR proposed reform of a post-selection time period for states to negotiate an alternate cost allocation method for selected Long-Term Regional Transmission Facilities (or portfolios of such Facilities) when an *ex ante* cost allocation method would otherwise apply.³⁰¹⁵

1415. We clarify that, if the Relevant State Entities indicate to transmission providers, as part of the required Engagement Period outlined above, that the Relevant State Entities have agreed to a State Agreement Process, and the

transmission providers decide to include that State Agreement Process in their final order compliance filings, then the transmission providers must also detail the State Agreement Process in proposed tariff provisions to their OATTs. The tariff provisions must describe how agreement would be reached regarding the cost allocation method for Long-Term Regional Transmission Facilities pursuant to the State Agreement Process, which also necessarily requires that it be clear which entities can participate in the specific State Agreement Process.³⁰¹⁶ This requirement is in furtherance of one of the goals of the final order, which is to allow a greater role for states in establishing a cost allocation method for Long-Term Regional Transmission Facilities (or portfolios of such Facilities).

1416. As noted above, after the required initial Engagement Period, a State Agreement Process could include other entities beyond Relevant State Entities, and those entities would need to be enumerated in the State Agreement Process included in the OATT. Transmission providers must first specify in their OATTs a description of how such voluntary agreements by the Relevant State Entities may be shared with transmission providers, as well as whether the transmission providers voluntarily agree to undertake an obligation to file the agreed-upon cost allocation method with the Commission for consideration under FPA section 205 (in other words, whether the transmission providers voluntarily waive their FPA section 205 filing rights such that they commit themselves to file with the Commission any cost allocation method that results from the State Agreement Process). Their OATT provisions must, at a minimum, also include the event triggering the beginning of the State Agreement Process, the duration of the State Agreement Process (not to exceed six months after selection), and a description of the Long-Term Regional Transmission Facilities to which the process applies. Further, the State Agreement Process procedures outlined in transmission providers' OATTs must set forth the manner in which a transmission provider would file a section 205 filing to seek Commission acceptance of a cost allocation method resulting from a State Agreement Process. We note that Relevant State Entities that participate in a State Agreement Process may need to provide relevant information to transmission

³⁰¹² NOPR, 179 FERC ¶ 61,028 at P 317.

³⁰¹³ For example, transmission providers may voluntarily agree as part of a State Agreement Process in their OATTs that transmission providers shall file any cost allocation method that meets the requirements of their State Agreement Process, even if those transmission providers do not agree with that method.

³⁰¹⁴ See Evergreen Action Initial Comments at 6; MISO Initial Comments at 67–68; National Grid Initial Comments at 25–26.

³⁰¹⁵ California Commission Initial Comments at 56; Kentucky Commission Chair Chandler Initial Comments at 4; Louisiana Commission Initial Comments at 34–35; NARUC Initial Comments at 52–53; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27–28.

³⁰¹⁶ NOPR, 179 FERC ¶ 61,028 at P 313.

providers to enable them to demonstrate that any cost allocation method that results from a State Agreement Process is just, reasonable, and not unduly discriminatory or preferential, and allocates cost in a manner that is at least roughly commensurate with estimated benefits.

1417. We do not agree with the commenters that recommend against memorializing and filing cost allocation methods resulting from a State Agreement Process with the Commission.³⁰¹⁷ To fulfill the Commission's statutory obligations, any cost allocation method that results from a State Agreement Process must be filed for review by the Commission and determined to be just, reasonable, and not unduly discriminatory or preferential. In addition, we believe that transparency regarding such cost allocation methods and the opportunity for stakeholders, particularly those that will be responsible for paying the costs of Long-Term Regional Transmission Facilities, to comment on them are an important safeguard to ensure that costs are allocated in a manner that is at least roughly commensurate with estimated benefits.

1418. We will not specify the level of agreement among Relevant State Entities or other entities that is necessary before a transmission provider files a cost allocation method derived from a State Agreement Process. As a state-led process, we believe that Relevant State Entities should have the ability to determine this important facet of their State Agreement Process. To this end, we decline to require unanimity or a set minimum threshold for agreement of Relevant State Entities to participate in the State Agreement Process.

1419. Some commenters request that the Commission clarify whether and to what extent a cost allocation method that results from a State Agreement Process can impose costs on entities that do not agree to that cost allocation method. However, we decline to prejudge any State Agreement Process or any cost allocation method that may result from a State Agreement Process. Any cost allocation method for a Long-Term Regional Transmission Facility (or portfolio of such Facilities) that results from a State Agreement Process must be filed with the Commission pursuant to FPA section 205, and the Commission must make a finding as to whether that cost allocation method is just, reasonable, and not unduly discriminatory or preferential. And, as noted above, we reiterate that all cost

allocation methods, including those resulting from a State Agreement Process, must allocate costs in a manner that is at least roughly commensurate with estimated benefits.³⁰¹⁸ Parties are free to raise any concerns about the costs that they may be allocated under a State Agreement Process-derived cost allocation method if and when that method is filed with the Commission.³⁰¹⁹

1420. MISO asks that the final order make clear that transmission providers can make necessary changes to the competitive transmission developer selection process to accommodate the State Agreement Process.³⁰²⁰ We clarify that the Commission will review any proposed changes to transmission providers' competitive transmission developer selection processes to accommodate State Agreement Processes as part of their compliance filings to this final order.

1421. With respect to California Municipal Utilities' and TANC's requests that the Commission require that local regulatory authorities be included in any State Agreement Process, the Mississippi Commission's statement that it would support expanding the State Agreement Approach to include non-jurisdictional utilities, we do not proscribe in this final order that the State Agreement Processes include other entities beyond Relevant State Entities. However, as noted above, Relevant State Entities have the option to include the participation of other entities in a State Agreement Process. Finally, with respect to US DOE's comments related to the jurisdictional implications of Federal power marketing administrations participating in State Agreement Processes, we do not establish any specific requirements for how State Agreement Processes will be designed. To the extent that a Federal power marketing administration does participate in such a process, it may advocate that such process facilitates its participation in a manner that is consistent with its statutory authority.³⁰²¹

4. Filing Rights Under the FPA

a. Comments

1422. A number of commenters express concerns that a requirement to seek agreement from Relevant State

Entities regarding a cost allocation approach could conflict with transmission providers' filing rights under the FPA.³⁰²² For example, AEP contends that in at least one region where AEP operates, such a requirement would deprive transmission owners of their exclusive right to file tariffs governing the rates and terms of their transmission service under section 205 of the FPA. AEP states that in *Atlantic City Electric Company v. FERC*, the D.C. Circuit, held that "[w]hen FERC attempts to deprive the utilities of their rights to initiate rate design changes with respect to services provided by their own assets, FERC has exceeded its jurisdiction."³⁰²³

1423. Similarly, Dominion reminds the Commission that the transmission provider has FPA section 205 rights, and that those rights cannot be ceded to the state through this proceeding.³⁰²⁴ National Grid asserts that the FPA gives transmission providers the ability to make section 205 filings on cost allocation, and that the State Agreement Process should be based on transmission providers voluntarily affording a role for states.³⁰²⁵

1424. APPA contends that requiring public utilities to file rate terms dictated by non-public utility entities raises jurisdictional issues under the FPA. APPA does not believe it is reasonable to provide to state regulators exclusive authority over the proposed cost allocation method in the absence of agreement by relevant stakeholders, and argues that if the Commission requires public utilities to file cost allocation methods agreed to by Relevant State Entities, public power utilities should be considered Relevant State Entities have a formal voting role in agreeing on

³⁰²² AEP Initial Comments at 6, 36 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9–11 ("[T]his Court, among others, has stressed that the power to initiate rate changes rests with the utility and cannot be appropriated by FERC in the absence of a finding that the existing rate was unlawful."); *Atl. City Elec. Co. v. FERC*, 329 F.3d 856, 858–59 (D.C. Cir. 2003) (per curiam)); MISO Initial Comments at 63–64 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9–11); MISO TOs Initial Comments at 37, 39–40 (citing 16 U.S.C. 824d; *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9–11; *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042, at P 107 (2010); *Mass. Dep't of Pub. Utils. v. FERC*, 729 F.2d 886, 887–88 (1st Cir. 1984)); PPL Initial Comments at 25 & n.66 ("[T]he *Atlantic City* case makes clear that the transmission owners are able to make Section 205 filings regarding cost allocation without additional conditions and the Commission cannot compel the transmission owners to cede these rights.").

³⁰²³ AEP Initial Comments at 36 (quoting *Atl. City Elec. Co. v. FERC*, 329 F.3d at 859); accord MISO Initial Comments at 63; MISO TOs Initial Comments at 40; PPL Initial Comments at 25 n.66.

³⁰²⁴ Dominion Initial Comments at 48–49 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1; *Atl. City Elec. Co. v. FERC*, 329 F.3d 856).

³⁰²⁵ National Grid Initial Comments at 25.

³⁰¹⁷ Mississippi Commission Initial Comments at 27–28; OMS Initial Comments at 12–13.

³⁰¹⁸ See *ICC v. FERC I*, 576 F.3d at 477; *ICC v. FERC III*, 756 F.3d at 564.

³⁰¹⁹ E.g., New England Systems Initial Comments at 23; Pennsylvania Commission Initial Comments at 12; Mississippi Commission Reply Comments at 3.

³⁰²⁰ MISO Initial Comments at 68–70.

³⁰²¹ US DOE Initial Comments at 50.

the cost allocation method(s) for Long-Term Regional Transmission Facilities.³⁰²⁶ Six Cities and Large Public Power argue that the Commission's proposal is an unlawful delegation of the Commission's exclusive statutory authority over rates under the FPA.³⁰²⁷

1425. Some commenters seek clarification on the Commission's proposal. MISO and Vistra request that the Commission clarify that nothing in the final order should be read to override or diminish the filing rights held, jointly and/or individually, by the RTOs/ISOs and their transmission owning members.³⁰²⁸ Indicated PJM TOs argue that, while seeking the agreement of Relevant State Entities is appropriate, the Commission does not have the authority to require that transmission providers obtain their agreement.³⁰²⁹ Similarly, WIRES states that the Commission should clarify that transmission providers are only required to seek agreement of Relevant State Entities and that they are not required to achieve such agreement.³⁰³⁰ Duke asserts that the Commission should clarify and revise the proposed State Agreement Process to ensure that it does not conflict with transmission providers' FPA section 205 rights to initiate rate changes.³⁰³¹

1426. PJM States propose that if retail regulators reach an agreement on cost allocation, transmission providers should be required to file it for consideration under section 205 of the FPA.³⁰³² PJM States recommend that if the transmission providers in a transmission planning region prefer a different cost allocation method, they can file their preferred alternative while also presenting the method agreed on by the Relevant State Entities.³⁰³³ PJM

States add that these proposals should be "balanced" and explain how the retail regulators' preferences were considered.³⁰³⁴ Similarly, NESCOE states that in cases of disagreement between state entities and transmission providers, they would prefer that the transmission providers file a state-preferred cost allocation method alongside their own preferred method, arguing that such an approach would respect the FPA section 205 rights that public utilities hold.³⁰³⁵ Similarly, New Jersey Commission recommends that in the event that the transmission provider disagrees with the approach desired by states, the Commission should require them to submit the states' approach as well as their own in their section 205 filing. New Jersey Commission proposes that the Commission would then decide which OATT filing to accept.³⁰³⁶

1427. Entergy contends that the proposal is within the Commission's authority because the Commission's proposal allows transmission providers to retain their filing rights consistent with *Atlantic City*. Entergy argues that the NOPR proposal does not conflict with *Atlantic City* because it would only establish a process where states are consulted on designing a cost allocation method, and that transmission providers still must make a cost allocation filing, even if there is no agreement.³⁰³⁷

b. Commission Determination

1428. As a threshold matter, we note that the Commission is acting pursuant to FPA section 206 in this final order. Under FPA section 206, the Commission has determined that existing regional transmission planning and cost allocation requirements are unjust, unreasonable, unduly discriminatory or preferential, and thus has both the authority and responsibility to establish a just and reasonable replacement rate consistent with the final order's requirements.³⁰³⁸

1429. As to commenters' FPA section 205 arguments, we find that our directives in this final order regarding the development of a State Agreement Process and any cost allocation methods to which the Relevant State Entities agree pursuant to that process do not alter existing FPA section 205 filing

rights.³⁰³⁹ Specifically, we clarify that, after the required Engagement Period, transmission providers in each transmission planning region will decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file as part of their compliance filings.³⁰⁴⁰ Therefore, transmission providers in a transmission planning region could elect to propose on compliance a Long-Term Regional Transmission Cost Allocation Method and not file a State Agreement Process or other *ex ante* cost allocation method to which Relevant State Entities agreed. In addition, we do not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs. In the same vein, we decline to require, as PJM States, NESCOE, and New Jersey Commission suggest, that transmission providers file two cost allocation methods—the transmission providers' preferred cost allocation method and the cost allocation method agreed to by the Relevant State Entities—if the transmission providers disagree with a proposed cost allocation method to which the Relevant State Entities agree.³⁰⁴¹ Entities that oppose or prefer a different cost allocation method than the transmission providers' preferred cost allocation method can provide their comments if and when such cost allocation method is filed with the Commission.

1430. We further clarify that unless voluntarily waived, a transmission provider retains its FPA section 205 filing rights to submit an *ex ante* cost allocation method for Long-Term Regional Transmission Facilities at any time,³⁰⁴² consistent with any limitations a transmission provider may have agreed to, for example, as part of its membership in an RTO/ISO. In response

³⁰²⁶ APPA Initial Comments at 42–45.

³⁰²⁷ Large Public Power Initial Comments at 37–38 (citing *City of Tacoma v. FERC*, 331 F.3d 106, 115 (D.C. Cir. 2002) (finding that the Commission unlawfully delegated its responsibility to assess annual charges imposed under the FPA against hydroelectric utilities licenses to other Federal agencies) (additional citations omitted)); Six Cities Initial Comments at 8–9 (citing 16 U.S.C. 824d(a), 824e; *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 965–66 (1986); *EPSA*, 577 U.S. at 277).

³⁰²⁸ MISO Initial Comments at 64; Vistra Initial Comments at 29–30.

³⁰²⁹ Indicated PJM TOs Initial Comments at 20 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d at 10–11).

³⁰³⁰ WIRES Initial Comments at 12 (citing 16 U.S.C. 824d; *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9–11; *Atl. City Elec. Co. v. FERC*, 329 F.3d at 858–59).

³⁰³¹ Duke Initial Comments at 39 (citing *Atl. City Elec. Co. v. FERC*, 329 F.3d at 858–59).

³⁰³² PJM States Initial Comments at 10 (citing NOPR, 179 FERC ¶ 61,028 at P 303).

³⁰³³ *Id.* at 10.

³⁰³⁴ *Id.* at 10.

³⁰³⁵ NESCOE Reply Comments at 4.

³⁰³⁶ New Jersey Commission Initial Comments at 17–18.

³⁰³⁷ Entergy Initial Comments at 31–33 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d at 11).

³⁰³⁸ 16 U.S.C. 824e(a) ("[T]he Commission shall determine the just and reasonable . . . practice . . . to be thereafter observed and in force, and shall fix the same by order." (emphasis added)).

³⁰³⁹ See Dominion Initial Comments at 48–49 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1; *Atl. City Elec. Co. v. FERC*, 329 F.3d 856).

³⁰⁴⁰ We note that the filing must include a Long-Term Regional Transmission Cost Allocation Method (*i.e.*, an *ex ante* cost allocation method).

³⁰⁴¹ PJM States Initial Comments at 10; NESCOE Reply Comments at 4; New Jersey Commission Initial Comments at 17–18.

³⁰⁴² See *Atl. City Elec. Co. v. FERC*, 295 F.3d at 9–11; *Atl. City Elec. Co. v. FERC*, 329 F.3d at 858–859.

to MISO and Vistra,³⁰⁴³ we also clarify that nothing in this final order should be read to override or diminish the filing rights held, jointly or individually, by RTOs/ISOs and their transmission owning members.

1431. In response to commenters arguing that the NOPR proposal to require transmission providers to seek agreement of Relevant State Entities regarding the Long-Term Regional Transmission Cost Allocation Method, State Agreement Process, or combination thereof would interfere with transmission providers' filing rights under FPA section 205,³⁰⁴⁴ those concerns are moot, as we decline to adopt this NOPR proposal, as discussed above. We reiterate that transmission providers retain their right to decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file in compliance with this final order after the Engagement Period.

5. Time Period and Related Issues in the Long-Term Regional Transmission Planning Cost Allocation Processes for State-Negotiated Alternate Cost Allocation Method

a. NOPR Proposal

1432. In the NOPR, the Commission proposed to require transmission providers to detail in their OATTs a process to provide a state or states (in multi-state transmission planning regions) with a time period to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method (*i.e.*, Long-Term Regional Transmission Cost Allocation Method) that would otherwise apply. During this time period, if a state or all states within the transmission planning region in which the selected regional transmission facility will be located unanimously agree on an alternate cost allocation method, the transmission provider may elect to file that method with the Commission for consideration under FPA section 205. The Commission explained that the transmission provider may elect to file an alternate cost allocation method because doing so increases the likelihood that relevant stakeholders perceive the cost allocation as fair and

that the needed regional transmission facilities will actually be constructed.³⁰⁴⁵

1433. If the relevant state or states cannot agree on an alternate cost allocation method memorialized in writing within the specified timeframe after a transmission developer's transmission facility is selected through Long-Term Regional Transmission Planning (*e.g.*, 90 days), the Commission proposed that then the transmission developer would be entitled to use any *ex ante* Long-Term Regional Transmission Cost Allocation Method that would otherwise apply for that Long-Term Regional Transmission Facility.³⁰⁴⁶

1434. In particular, the Commission proposed to require that the OATT provisions that describe the state-negotiated alternate cost allocation method include when this time period will occur, what its duration will be, and an affirmation that any alternate cost allocation method must be submitted to the Commission for review and approval under FPA section 205 prior to taking effect. Under this proposal, when filed, the Commission would evaluate the alternate cost allocation method to ensure that it is just and reasonable and allocates costs in a manner that is at least roughly commensurate with estimated benefits. If the Commission rejects a state-negotiated alternate cost allocation method, the transmission developer of the Long-Term Regional Transmission Facility would be entitled to use the applicable *ex ante* regional cost allocation method that would have applied to it in the absence of the proposed alternative cost allocation method.³⁰⁴⁷ The Commission proposed to prescribe a 90-day time period for a state-negotiated cost allocation method to be memorialized in writing.³⁰⁴⁸

1435. Finally, the Commission sought comment on whether to establish a requirement for a time period for state involvement in regional cost allocation for transmission facilities selected in existing near-term reliability and economic regional transmission planning processes.³⁰⁴⁹

b. Comments

1436. Several commenters support the Commission's proposal to require transmission providers to detail in their OATTs a process to provide a state or states with a time period to negotiate a

cost allocation method for a transmission facility (or portfolio of facilities) selected through Long-Term Regional Transmission Planning that is different than any *ex ante* regional cost allocation method (*i.e.*, Long-Term Regional Transmission Cost Allocation Method).³⁰⁵⁰ NESCOE, Pennsylvania Commission, and PJM States support a requirement for transmission providers to detail in their OATT provisions that describe the state-negotiated cost allocation method.³⁰⁵¹ Clean Energy Buyers, Dominion, and PIOs agree that any alternate cost allocation method must be submitted to the Commission for review and approval under FPA section 205 prior to taking effect.³⁰⁵²

1437. PJM and Nebraska Commission support the proposal to require a time period for state-negotiated alternate cost allocation with suggested modifications. Nebraska Commission states that a process that builds consensus is important for contentious issues such as cost allocation and suggests adoption of a model similar to SPP's Regional State Committee, which it contends has a proven track record for achieving consensus among stakeholders.³⁰⁵³ PJM recommends that the Commission provide clear direction as to the circumstances under which a process for states to negotiate an alternate cost allocation method would be appropriate. PJM also proposes that states seeking a state-negotiated alternate cost allocation method should be required to explain why the *ex ante* cost allocation method is not appropriate for the identified transmission facility or facilities.³⁰⁵⁴

1438. PJM States disagree, arguing that there is no proposed requirement that retail regulators show why an *ex ante* approach is inappropriate before agreeing to and advocating for an alternate. PJM States further assert that allowing states to agree on an alternate cost allocation approach after seeing what transmission projects are selected may be beneficial since states will have more information on specific projects.³⁰⁵⁵

³⁰⁴³ MISO Initial Comments at 64; Vistra Initial Comments at 29–30.

³⁰⁴⁴ AEP Initial Comments at 36; APPA Initial Comments at 42; Dominion Initial Comments at 48–49; MISO Initial Comments at 63–64; MISO TOs Initial Comments at 37, 39–40; MISO TOs Reply Comments at 5–7; PPL Initial Comments at 25 & n.66.

³⁰⁴⁵ NOPR, 179 FERC ¶ 61,028 at P 319.

³⁰⁴⁶ *Id.* P 320.

³⁰⁴⁷ *Id.* P 322.

³⁰⁴⁸ *Id.* P 323.

³⁰⁴⁹ *Id.* P 324.

³⁰⁵⁰ Entergy Initial Comments at 29–30; Nebraska Commission Initial Comments at 9; New England for Offshore Wind Initial Comments at 5; Northwest and Intermountain Initial Comments at 18–19; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27–28; PIOs Initial Comments at 69; SEIA Initial Comments at 24.

³⁰⁵¹ NESCOE Initial Comments at 71; Pennsylvania Commission Initial Comments at 16; PJM States Initial Comments at 12–13.

³⁰⁵² Clean Energy Buyers Initial Comments at 29–30; Dominion Initial Comments at 52; PIOs Initial Comments at 71.

³⁰⁵³ Nebraska Commission Initial Comments at 9.

³⁰⁵⁴ PJM Initial Comments at 117.

³⁰⁵⁵ PJM States Reply Comments at 6.

1439. Some commenters seek clarification on the NOPR proposal. Pennsylvania Commission explains that because this negotiation would occur after transmission facility selection, it is an *ex post* “State Agreement Process.” As such, Pennsylvania Commission contends, it could create confusion if the Commission does not clarify that different rules apply to the 90-day “renegotiation” process.³⁰⁵⁶ Similarly, MISO states that it is not clear whether the proposed requirements are intended as an alternative to the State Agreement Process or to define how the State Agreement Process would be implemented.³⁰⁵⁷

1440. Some commenters oppose a requirement to provide a time period for a state or states to negotiate a cost allocation method for a transmission facility (or portfolio of facilities) selected in the regional transmission plan that is different than any *ex ante* regional cost allocation method (i.e., Long-Term Regional Transmission Cost Allocation Method) that would otherwise apply.³⁰⁵⁸ Dominion and Idaho Power argue that the Commission should permit regional flexibility as to whether to adopt such a time period.³⁰⁵⁹ Idaho Power further contends that the Commission’s transmission planning processes are not the primary barriers to transmission development; instead, Federal permitting and siting processes and coordination with stakeholders are greater barriers.³⁰⁶⁰

1441. MISO recommends that rather than requiring the specific process and *ex post* opportunities for states to negotiate an alternate cost allocation method, the Commission should identify the opportunity for state involvement in the development of cost allocation and leave the details for that involvement to each transmission planning region.³⁰⁶¹ Pennsylvania Commission states that it does not view the time period for state-negotiated alternate cost allocation as a principal negotiation method for cost allocation and asserts that more appropriate processes are the proposed State

Agreement Process or PJM’s existing State Agreement Approach.³⁰⁶²

1442. Dominion supports allowing but not requiring that *ex ante* processes be coupled with an option for states to propose an alternate method, stating that the process for establishing an alternative cost allocation method could become cumbersome as the NOPR proposes to require it to comply with the six Order No. 1000 regional cost allocation principles.³⁰⁶³ Exelon recommends allowing states the opportunity to propose an alternative cost allocation method to the *ex ante* method after transmission project selection, but states that FPA section 205 rights holders should be able to accept, modify, or reject the proposed alternative cost allocation method. Exelon claims that this approach would respect the legal rights of transmission owners, pointing to PJM’s State Agreement Approach as an example.³⁰⁶⁴ NESCOE urges the Commission to reject Exelon’s request that transmission providers be free to accept or reject cost allocation methods proposed by state entities.³⁰⁶⁵

i. Permissive Right of Transmission Provider To File Alternate Cost Allocation Method With the Commission Upon Unanimous State Agreement

1443. NARUC and NESCOE argue that if states unanimously agree on an alternate cost allocation method, then the transmission provider should be obligated to file it.³⁰⁶⁶ NARUC states that the transmission provider may also file the cost allocation method that would otherwise apply if it concludes that the negotiated cost allocation method does not comply with the six Order No. 1000 regional cost allocation principles or is otherwise deficient. NARUC contends that this approach would not violate the transmission providers’ FPA section 205 filing rights.³⁰⁶⁷ Similarly, NESCOE asserts that the Commission should allow the transmission provider to file its preferred approach, but also require that the transmission provider file the state-negotiated alternate cost allocation method, an approach that could be modeled after existing provisions in NYISO and SPP.³⁰⁶⁸

1444. NESCOE also requests that the Commission clarify whether unanimity means that each opting-in state has agreed to fund the Long-Term Regional Transmission Facility or that all the states in the transmission planning region have agreed that a subset of states will fund the Long-Term Regional Transmission Facility.³⁰⁶⁹ NESCOE further requests that the Commission clarify how it intends to reconcile the unanimous agreement requirement in this proposal with the other NOPR proposal that gives states the ability to choose the definition of state agreement for purposes of a cost allocation method and where the NOPR expressed a willingness to abide by the bylaws of an individual regional state committee, which may not define agreement as full unanimity.³⁰⁷⁰

1445. Indiana Commission expresses concern that the requirement to obtain unanimous state approval regarding an *ex post* cost allocation process might prove unworkable. Indiana Commission argues that it may be unrealistic to expect that states can reach unanimity on something as contentious as cost allocation. Moreover, Indiana Commission is concerned that states may use the requirement for unanimous agreement to leverage their vote and to gain ground in other areas of contention.³⁰⁷¹

1446. PIOs seek clarification on the intent behind the NOPR language that “the public utility transmission provider *may elect* to file [a state-negotiated alternate cost allocation method] with the Commission for consideration under FPA section 205.”³⁰⁷² Similarly, Pennsylvania Commission and PJM States request clarification regarding whether transmission providers could choose not to file an alternative cost allocation method to which the states in a transmission planning region have unanimously agreed.³⁰⁷³ Pennsylvania Commission asserts that it sees no reason why a transmission provider should be able to override the unanimous agreement of affected states.³⁰⁷⁴

1447. In addition, PJM States recommend that to address the inability for states to voice their cost allocation concerns, the Commission should

³⁰⁵⁶ Pennsylvania Commission Initial Comments at 15.

³⁰⁵⁷ MISO Initial Comments at 71.

³⁰⁵⁸ Dominion Initial Comments at 51; Idaho Power Initial Comments at 10–11; PPL Initial Comments at 27.

³⁰⁵⁹ Dominion Initial Comments at 51; Idaho Power Initial Comments at 10–11.

³⁰⁶⁰ Idaho Power Initial Comments at 11 (noting National Environmental Policy Act review and siting decisions with the Bureau of Land Management as examples of Federal permitting and siting processes).

³⁰⁶¹ MISO Initial Comments at 71.

³⁰⁶² Pennsylvania Commission Initial Comments at 16.

³⁰⁶³ Dominion Initial Comments at 51.

³⁰⁶⁴ Exelon Initial Comments at 26–27.

³⁰⁶⁵ NESCOE Reply Comments at 3–4.

³⁰⁶⁶ NARUC Initial Comments at 53; NESCOE Initial Comments at 68.

³⁰⁶⁷ NARUC Initial Comments at 53.

³⁰⁶⁸ NESCOE Initial Comments at 68–70.

³⁰⁶⁹ *Id.* at 10, 67–68.

³⁰⁷⁰ *Id.* at 68 (citing NOPR, 179 FERC ¶ 61,028 at P 306 & n.512).

³⁰⁷¹ Indiana Commission Initial Comments at 5.

³⁰⁷² PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 319).

³⁰⁷³ Pennsylvania Commission Initial Comments at 16–17; PJM States Reply Comments at 6.

³⁰⁷⁴ Pennsylvania Commission Initial Comments at 17.

consider how it can afford retail regulators greater participation status in the FPA section 205 filing process.³⁰⁷⁵ Further, PJM States note that other regional states committees have varying processes, including the ability to request that a transmission provider file a cost allocation method on their behalf.³⁰⁷⁶

ii. Duration for the Time Period for State-Negotiated Cost Allocation

1448. A few commenters agree with the Commission's proposal to require a 90-day time period for a state-negotiated cost allocation method to be memorialized in writing.³⁰⁷⁷ For example, New England for Offshore Wind states that it is essential that deadlines are imposed to prevent delays caused by disagreements over cost allocation.³⁰⁷⁸ PIOs assert that the 90-day time period should begin when the transmission project or portfolio of projects is selected.³⁰⁷⁹

1449. Many commenters, however, argue that the 90-day time period is too short. For example, NARUC, National Grid, and Southern contend that 90 days may be insufficient time for the states in large, multi-state transmission planning regions to negotiate a cost allocation method.³⁰⁸⁰ Similarly, NRG argues that the Commission might consider alternative timelines for multi-state collaboration versus where there is a single state entity responsible for the cost allocation.³⁰⁸¹ US Chamber of Commerce contends that the 90-day timeline for state-negotiated cost allocation agreements is unreasonably tight and may undermine the potential for agreement.³⁰⁸²

1450. Several commenters, including state commissions, propose longer time periods. For example, California Commission, Kentucky Commission Chair Chandler, Louisiana Commission, NARUC, NRG, and Pacific Northwest State Agencies propose at least six months (180 days) as a more appropriate time period for state negotiation.³⁰⁸³

³⁰⁷⁵ PJM States Reply Comments at 6–7.

³⁰⁷⁶ *Id.* at 7.

³⁰⁷⁷ New England for Offshore Wind Initial Comments at 5; Northwest and Intermountain Initial Comments at 18; PIOs Initial Comments at 69; SEIA Initial Comments at 24.

³⁰⁷⁸ New England for Offshore Wind Initial Comments at 5.

³⁰⁷⁹ PIOs Initial Comments at 70.

³⁰⁸⁰ NARUC Initial Comments at 52–53; National Grid Initial Comments at 24–25; Southern Initial Comments at 7–8.

³⁰⁸¹ NRG Initial Comments at 21.

³⁰⁸² US Chamber of Commerce Initial Comments at 10.

³⁰⁸³ California Commission Initial Comments at 56; Kentucky Commission Chair Chandler Initial Comments at 4; Louisiana Commission Initial

Commission request that states should be provided with the opportunity to request extensions if they fail to agree on a cost allocation method after six months (180 days).³⁰⁸⁴ OMS recommends that the Commission establish periodic reporting requirements for transmission providers during the 90-day period with an option to extend the deliberations for good cause.³⁰⁸⁵

1451. Several other commenters contend that it should be left to the transmission planning regions, with input from states, to determine the appropriate time period.³⁰⁸⁶ For example, Dominion states that the Commission should not dictate any particular timetable and should instead evaluate proposals on a case-by-case basis.³⁰⁸⁷ Similarly, Nevada Commission proposes that the Commission require relevant state agencies to be involved in the process as early as possible, but to provide no less than 120 days to allow for appropriate notice and review of any state-negotiated agreement.³⁰⁸⁸ Exelon, Indiana Commission, and SERTP Sponsors recommend allowing flexibility in determining the appropriate time period to reflect regional differences.³⁰⁸⁹ Idaho Power agrees but cautions that any process should not extend the length of transmission planning processes or development.³⁰⁹⁰ Pennsylvania Commission also supports flexibility in determining the appropriate time period given that this process is new and there is little knowledge and experience with respect to how it will function in practice.³⁰⁹¹

1452. NESCOE and PJM States assert that NYISO's process referenced by the Commission can last longer than the 90-day time period for state-negotiated cost

Comments at 34–35; NARUC Initial Comments at 52–53; NRG Initial Comments at 21; Pacific Northwest State Agencies Initial Comments at 27–28.

³⁰⁸⁴ California Commission Initial Comments at 56; Louisiana Commission Initial Comments at 35.

³⁰⁸⁵ OMS Initial Comments at 13.

³⁰⁸⁶ Dominion Initial Comments at 51–52; Exelon Initial Comments at 28–29; Indiana Commission Initial Comments at 5–6; National Grid Initial Comments at 24–25; NESCOE Initial Comments at 71; Pennsylvania Commission Initial Comments at 16; PJM States Initial Comments at 12–13; SERTP Sponsors Initial Comments at 15.

³⁰⁸⁷ Dominion Initial Comments at 51–52.

³⁰⁸⁸ Nevada Commission Initial Comments at 13–14.

³⁰⁸⁹ Exelon Initial Comments at 28–29; Indiana Commission Initial Comments at 5–6; SERTP Sponsors Initial Comments at 15.

³⁰⁹⁰ Idaho Power Initial Comments at 10–11.

³⁰⁹¹ Pennsylvania Commission Initial Comments at 16.

allocation proposed in the NOPR.³⁰⁹² Further, NESCOE emphasizes that the NYISO process involves only one state entity, whereas other transmission planning regions have multiple states. Thus, NESCOE and PJM States argue, the Commission should allow transmission planning regions to determine what time period is appropriate.³⁰⁹³

1453. A few other commenters contend that state negotiation on an alternate cost allocation method should not be limited by any time period. For example, PPL asserts that limiting the timeframe merely lowers the chance of state agreement, and thus the prospects for the underlying transmission project to be constructed.³⁰⁹⁴ Southern states that the Commission should allow transmission planning regions to develop a process that has state support.³⁰⁹⁵ Similarly, Xcel contends that transmission planning regions should have as much time as needed to negotiate and identify cost allocation methods.³⁰⁹⁶

iii. Other Issues

1454. NESCOE, Northwest and Intermountain, PJM, and SEIA agree with the proposal that if states cannot unanimously agree on an alternate cost allocation method within the specified timeframe, then the transmission developer would be entitled to use the cost allocation method that would otherwise apply for that Long-Term Regional Transmission Facility.³⁰⁹⁷ In contrast, NRG recommends that in the case where states do not agree, the Commission could either require the transmission provider to make a filing or subject rival state filings to “jump ball” treatment. NRG contends that either of these approaches would encourage comity and resolution of states' differences.³⁰⁹⁸

1455. MISO and PPL oppose establishing a requirement for a time period for state involvement in regional cost allocation for transmission facilities selected in existing near-term reliability and economic regional transmission planning processes. MISO states that

³⁰⁹² NESCOE Initial Comments at 70–71 (citing NOPR, 179 FERC ¶ 61,028 at P 323); PJM States Initial Comments at 12–13 (citing *N.Y. Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,040, at PP 119–121 (2015)).

³⁰⁹³ NESCOE Initial Comments at 71; PJM States Initial Comments at 12–13.

³⁰⁹⁴ PPL Initial Comments at 27.

³⁰⁹⁵ Southern Initial Comments at 7–8.

³⁰⁹⁶ Xcel Initial Comments at 11–12.

³⁰⁹⁷ NESCOE Initial Comments at 70; Northwest and Intermountain Initial Comments at 19; PJM Initial Comments at 117–118; SEIA Initial Comments at 24.

³⁰⁹⁸ NRG Initial Comments at 21.

there is no evidence in the record of this proceeding to support extending the state involvement proposed in the NOPR to existing near-term transmission planning processes.³⁰⁹⁹ PPL argues that departures from an *ex ante* cost allocation method would lead to uncertainty, delay, and costly litigation.³¹⁰⁰

c. Commission Determination

1456. We decline to adopt the NOPR proposal to require transmission providers to provide a time period after selection of Long-Term Regional Transmission Facilities for states to negotiate an alternate cost allocation that is different than any *ex ante* regional cost allocation method that would otherwise apply. We find that requiring a time period after selection for states to negotiate an alternate *ex post* cost allocation method is largely duplicative given our decision above to allow the use of a State Agreement Process before or after the selection of a Long-Term Regional Transmission Facility (or a portfolio of such Facilities). Furthermore, having two separate processes that serve similar functions could add unnecessary complexity and create confusion in the cost allocation process.³¹⁰¹ Relevant State Entities will have an opportunity to provide input on and to potentially agree to a Long-Term Regional Transmission Cost Allocation Method(s) and/or a State Agreement Process as part of the Engagement Period that we require transmission providers to establish. We are also concerned that the burden associated with the NOPR proposal would have been significant, as it would have created a requirement to allow for such negotiations for all Long-Term Regional Transmission Facilities.

1457. Because we are declining to require that transmission providers establish a time period after selection of Long-Term Regional Transmission Facilities to allow states to negotiate an alternate *ex post* cost allocation method, we need not address the comments on the duration of such a time period and the requests for clarification by MISO,

Pennsylvania Commission, PIOs, and PJM States.³¹⁰²

B. Long-Term Regional Transmission Facility Cost Allocation Compliance With the Existing Six Order No. 1000 Regional Cost Allocation Principles

1. NOPR Proposal

1458. The Commission proposed to require that the Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities comply with the existing six Order No. 1000 regional cost allocation principles.³¹⁰³ The six regional transmission cost allocation principles adopted in Order No. 1000 are: (1) the costs of selected transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities; (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1; (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs; (5) the method for determining benefits and identifying beneficiaries must be transparent; and (6) there may be different regional cost allocation methods for different types of transmission facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.³¹⁰⁴

2. Comments

a. General Proposal

1459. Some commenters agree with the Commission's proposal that any Long-Term Regional Transmission Cost Allocation Method and any cost allocation method resulting from the State Agreement Process for Long-Term Regional Transmission Facilities must comply with the existing six Order No. 1000 regional cost allocation principles.³¹⁰⁵ APPA requests that the

Commission clarify that it is not requiring changes to existing Commission-approved Order No. 1000 regional cost allocation principles.³¹⁰⁶

1460. New Jersey Commission supports requiring that any negotiated cost allocation method, whether *ex ante* or *ex post*, comply with the Order No. 1000 regional cost allocation principles, except for Principle 4.³¹⁰⁷ New Jersey Commission opines that requiring that cost allocation methods be consistent with the beneficiary-pays principle is particularly necessary in a State Agreement Process to avoid potential free ridership.³¹⁰⁸

1461. Industrial Customers argue that, regardless of the cost allocation method that is chosen, the Commission should explicitly state that the cost causation principle must apply, as compliance with Order No. 1000 may not ensure compliance with cost causation principles on its own.³¹⁰⁹ Large Public Power argues that the Commission must hew closely to the first two principles governing cost allocation articulated in Order No. 1000: (1) that costs must be allocated in a way that is roughly commensurate with benefits; and (2) that there will be no involuntary allocation of costs to non-beneficiaries.³¹¹⁰ Pine Gate asserts that transmission providers must be required to propose cost allocation methods that comport with the well-established "roughly commensurate" principle.³¹¹¹ City of New Orleans Council and Ohio Commission Federal Advocate state that cost allocation must adhere to cost causation and beneficiary-pays principles.³¹¹²

1462. OMS states that it developed its own principles through a committee of regulators focused on cost allocation for long-range transmission projects in response to the NOPR, which include: (1) costs of new transmission projects should be allocated to cost causers and beneficiaries in a manner roughly commensurate with the costs caused and benefits of those projects; (2) cost

Initial Comments at 56; NRECA Initial Comments at 56; Ohio Consumers Initial Comments at 12–13.

³¹⁰⁶ APPA Initial Comments at 5.

³¹⁰⁷ New Jersey Commission Initial Comments at 18 (citing New Jersey Commission ANOPR Comments at 7–8 (explaining why it opposes Principle 4's policy of allowing beneficiaries in other transmission planning regions to evade all cost allocation for transmission projects that provide them with substantial benefits)).

³¹⁰⁸ *Id.*

³¹⁰⁹ Industrial Customers Initial Comments at 23–24.

³¹¹⁰ Large Public Power Initial Comments at 29.

³¹¹¹ Pine Gate Initial Comments at 42–44.

³¹¹² City of New Orleans Council Initial Comments at 10; Ohio Commission Federal Advocate Initial Comments at 14.

³⁰⁹⁹ MISO Initial Comments at 71.

³¹⁰⁰ PPL Initial Comments at 27–28.

³¹⁰¹ See, e.g., MISO Initial Comments at 71 (seeking clarification as to whether the proposed time period for states to negotiate cost allocation is an alternative to the State Agreement Process); Pennsylvania Commission Initial Comments at 16 (stating that it does not view the proposed time period as the principal method for negotiating cost allocation and that the more appropriate process is the proposed State Agreement Process).

³¹⁰² MISO Initial Comments at 71; Pennsylvania Commission Initial Comments at 15; PIOs Initial Comments at 71 (citing NOPR, 179 FERC ¶ 61,028 at P 319); PJM States Reply Comments at 6.

³¹⁰³ NOPR, 179 FERC ¶ 61,028 at P 302.

³¹⁰⁴ Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 637, 646, 657, 668, 685.

³¹⁰⁵ APPA Initial Comments at 40; Dominion Initial Comments at 45; Kentucky Commission Chair Chandler Initial Comments at 3; NESCOE

allocation should be as granular and accurate as possible such that benefit-cost analysis uses metrics that are quantifiable, capable of replication, non-duplicative, and forward-looking; (3) costs should not be allocated to parties that receive negligible or negative benefits; and (4) generators and load each can be considered cost causers, beneficiaries, or both and should be allocated costs accordingly.³¹¹³ Louisiana Commission supports OMS' position on benefit metrics as articulated in OMS' second principle.³¹¹⁴ OMS highlights that regional flexibility must be preserved, pointing to MISO's Targeted Market Efficiency Projects process as an example of a process that did not strictly comply with Order No. 1000 but was effective and widely supported.³¹¹⁵

1463. Ohio Consumers argue that the Commission should espouse three fundamental principles when considering the benefits and cost allocations associated with any Long-Term Regional Transmission Facilities: (1) costs should be allocated to those who caused the costs to be incurred; (2) subsidies are bad for competitive markets, because they result in noncompetitive outcomes and inaccurate price signals; and (3) consumers should not be charged until transmission projects are found to be used and useful.³¹¹⁶ Also, Ohio Consumers assert, cost allocations to consumers should adhere to the Commission's current ratemaking standards in PJM.³¹¹⁷

1464. PIOs assert that the Commission should require that transmission providers demonstrate on compliance that the cost allocation method complies with the beneficiary-pays principle by considering all quantifiable benefits.³¹¹⁸ ELCON states that cost allocation proposals must comply with the cost causation principle "by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." ELCON remains concerned that, in an effort to reach public policy goals, costs will be socialized among all consumers without consideration of the cost causers, and states that cost allocation must evaluate the drivers of the specific transmission need and the party that caused the need for the additional transmission.³¹¹⁹ Utah

Division of Public Utilities asks that when states or other stakeholders disagree on the cost allocation method due to differing renewable goals, the Long-Term Regional Transmission Cost Allocation Method be required to use cost causation principles to determine what portion of the proposed transmission projects are due to state policies.³¹²⁰

1465. West Virginia Commission states that it supports retention of the cost-causation principles in Order No. 1000, noting that the Order No. 1000 cost allocation principles are grounded in the beneficiary-pays principle that the costs of transmission facilities should be allocated commensurate with the benefits of those facilities. However, West Virginia Commission contends that the beneficiary-pays principle cannot and should not be applied on a presumptive regional basis when new transmission is identified as needed to accommodate one or more states' public policy decisions.³¹²¹ West Virginia Commission states that longstanding legal precedent on cost causation and ratemaking principles require that rates remain just and reasonable, that customers pay for transmission upgrades based upon their roughly commensurate benefits, and that new generators, or the willing and voluntary benefactors of new generators, pay the costs for the interconnection-related network upgrades if such upgrades would not be needed but for the new generators.³¹²² West Virginia Commission contends that to adopt a cost allocation that requires any non-volunteering state to pay costs caused by another state's public policies would depart from years of Commission precedent and would be unjust and unreasonable.³¹²³

1466. Vermont Electric and Vermont Transco encourage the Commission to ensure that any cost allocation approach ensures that the benefits of transmission facilities are roughly commensurate with the costs thereof for both small

rural states and larger, more populated states. Vermont Electric and Vermont Transco argue that the final order should reflect equitable principles in accordance with which the significant investments made by Vermont prior to the issuance of the final order are taken into account in cost allocation processes.³¹²⁴ MISO states that the final order should not preclude applying different cost allocation methods to transmission projects of the same type, noting that Order No. 2000 contemplated "the potential for different cost allocation methodologies" as RTO/ISO footprints grew.³¹²⁵

b. Comments Specific to a State Agreement Process

1467. Certain commenters discuss the interaction between the Order No. 1000 regional cost allocation principles and any cost allocation methods resulting from the State Agreement Process. Pennsylvania Commission supports the proposed requirement while also contending that the Commission should defer to unanimous agreement by affected states.³¹²⁶ Avangrid argues that the Commission should relax this requirement and defer to the balance achieved via state agreement.³¹²⁷ Mississippi Commission argues that the proposed requirement is unnecessary because the State Agreement Process will result in voluntary assumption of costs.³¹²⁸ Likewise, PacifiCorp and NV Energy argue that the Order No. 1000 regional cost allocation principles should not apply to the State Agreement Process because there will be no involuntary cost allocation given that states have already agreed. They further contend that beneficiary analyses and minimum cost-benefit ratios will foreclose state-favored cost allocation solutions.³¹²⁹ PacifiCorp and NV Energy argue that agreeing to cost allocation will be a difficult task for states, and the Commission should not further dictate the type of agreement.³¹³⁰

1468. PJM States ask the Commission not to preclude or limit the availability of the PJM State Agreement Approach, which they assert is not required to comply with the Order No. 1000

³¹²⁰ Utah Division of Public Utilities Initial Comments at 9–10.

³¹²¹ West Virginia Commission Reply Comments at 3; West Virginia Commission Supplemental Comments at 3–4.

³¹²² West Virginia Commission Reply Comments at 6 (citing *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *ICC v. FERC I*, 576 F.3d at 477; *ISO New England, Inc.*, 115 FERC ¶ 61,145, at P 13 (2006), *aff'd*, *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (D.C. Cir. 2015); *El Paso Elec. Co. v. FERC*, 832 F.3d 495, 499–500 & n.10 (5th Cir. 2016); *Midcontinent Indep. Sys. Operator, Inc.*, 159 FERC ¶ 63,016, at P 138 (2017), *aff'd*, 164 FERC ¶ 61,194 (2018); Order No. 1000, 136 FERC ¶ 61,051 at P 622); West Virginia Commission Supplemental Comments at 5–6.

³¹²³ West Virginia Commission Reply Comments at 6–7.

³¹²⁴ Vermont Electric and Vermont Transco Initial Comments at 3–4.

³¹²⁵ MISO Reply Comments at 17–19.

³¹²⁶ Pennsylvania Commission Initial Comments at 13.

³¹²⁷ Avangrid Initial Comments at 30.

³¹²⁸ Mississippi Commission Initial Comments at 25.

³¹²⁹ PacifiCorp and NV Energy Initial Comments at 17.

³¹³⁰ *Id.*

³¹¹³ OMS Initial Comments at 12.

³¹¹⁴ Louisiana Commission Reply Comments at 10.

³¹¹⁵ OMS Initial Comments at 13.

³¹¹⁶ Ohio Consumers Initial Comments at 6–7, 12–14.

³¹¹⁷ *Id.* at 1.

³¹¹⁸ PIOs Initial Comments at 68.

³¹¹⁹ ELCON Initial Comments at 15.

regional cost allocation principles.³¹³¹ Similarly, Exelon notes that the Commission has indicated that voluntary state cost allocation agreements need not comply with Order No. 1000.³¹³² Therefore, Exelon asks the Commission to clarify that the proposed State Agreement Process is supplementary to any previously accepted provisions for state agreement-based cost allocation.³¹³³

3. Commission Determination

1469. We adopt the NOPR proposal, with modification, to require Long-Term Regional Transmission Cost Allocation Methods to comply with five of the six existing Order No. 1000 regional cost allocation principles. Specifically, we require transmission providers in each transmission planning region to demonstrate on compliance with this final order that any Long-Term Regional Transmission Cost Allocation Methods, that they propose that Relevant State Entities have *not* indicated that they agree to, comply with Order No. 1000 regional cost allocation principles (1) through (5). However, we do not require transmission providers to demonstrate that any Long-Term Regional Transmission Cost Allocation Methods that they propose complies with Order No. 1000 regional cost allocation principle (6), and, as a result, unlike under Order No. 1000, transmission providers cannot adopt different Long-Term Regional Transmission Cost Allocation Methods for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.

1470. However, as discussed further below, we do not adopt the NOPR proposal to require compliance with the Order No. 1000 regional cost allocation principles in two situations. First, we do not require a Long-Term Regional Transmission Cost Allocation Method to comply with any of the Order No. 1000 regional cost allocation principles *if* Relevant State Entities indicate that they agreed to that method as part of the Engagement Period. Second, we do not require a cost allocation method resulting from a State Agreement Process to comply with the Order No. 1000 regional cost allocation principles.

1471. The first five Order No. 1000 regional transmission cost allocation

principles are: (1) the costs of selected transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits;³¹³⁴ (2) those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities;³¹³⁵ (3) a benefit to cost threshold ratio, if adopted, cannot exceed 1.25 to 1;³¹³⁶ (4) costs must be allocated solely within the transmission planning region unless another entity outside the region voluntarily assumes a portion of those costs;³¹³⁷ and (5) the method for determining benefits and identifying beneficiaries must be transparent.³¹³⁸

1472. We find that Order No. 1000 regional cost allocation principles (1) through (5) remain relevant for *ex ante* cost allocation methods for Long-Term Regional Transmission Facilities that transmission providers propose on compliance but with which Relevant State Entities have *not* indicated their agreement. In Order No. 1000, regarding regional cost allocation principle (1), the Commission stated that “[r]equiring a beneficiaries pay cost allocation method or methods is fully consistent with the cost causation principle as recognized by the Commission and the courts.”³¹³⁹ Since making that statement, the Commission and the courts have only further strengthened this connection between beneficiaries-pay cost allocation and the cost causation principle.³¹⁴⁰ Similarly, principle (2) continues to “express[] a central tenet of cost causation” and is “thus essential to proper cost allocation.”³¹⁴¹

1473. Concerning regional cost allocation principle (3), as noted in Order No. 1000, transmission providers may choose to establish such a threshold to mitigate against uncertainty in the measurement of benefits and costs, and this principle limits the threshold to one that is not so high as to block inclusion of many worthwhile transmission projects in the regional

transmission plan.³¹⁴² As to regional cost allocation principle (4), this final order maintains the close link established by Order No. 1000 between regional transmission planning and cost allocation to the region being planned for.³¹⁴³ Further, we find, similar to the Commission’s findings in Order No. 1000, that removing regional cost allocation principle (4) would be tantamount to interconnection-wide transmission planning because unilateral allocation of costs from one transmission planning region to another would require stakeholders to actively monitor regional transmission planning processes in numerous other regions.³¹⁴⁴ Lastly, we find, similar to Order No. 1000, that regional cost allocation principle (5) will ensure that Long-Term Regional Transmission Cost Allocation Methods are just and reasonable and not unduly discriminatory or preferential, will help aid in development and construction of new transmission, and may avoid contentious litigation or prolonged debate among stakeholders.³¹⁴⁵

1474. In contrast to the first five regional cost allocation principles, Order No. 1000 regional cost allocation principle (6) is inconsistent with Long-Term Regional Transmission Planning as directed in this final order. Order No. 1000 Regional cost allocation principle (6) provides that there may be different regional cost allocation methods for different types of transmission facilities in the regional transmission plan but that there can be only one cost allocation method for each type of facility, and that method must be determined in advance.³¹⁴⁶ As we explain below, however, transmission providers may not establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may not establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types. Permitting such project-type-limited Long-Term Regional Transmission Cost Allocation Methods would be inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning that we require in this final order. Accordingly, in declining to require that Long-Term Regional

³¹³¹ PJM States Initial Comments at 11–12 (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 142).

³¹³² Exelon Initial Comments at 27–28 (citing *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at P 4).

³¹³³ Exelon Initial Comments at 27–28 (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214).

³¹³⁴ Order No. 1000, 136 FERC ¶ 61,051 at P 622.

³¹³⁵ *Id.* P 637.

³¹³⁶ *Id.* P 646.

³¹³⁷ *Id.* P 657.

³¹³⁸ *Id.* P 668.

³¹³⁹ *Id.* P 623. See also *id.* P 586 & n.453 (citing *ICC v. FERC I*, 576 F.3d at 476–77; *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1369 (D.C. Cir. 2004); *Sithe/Indep. Power Partners, L.P. v. FERC*, 285 F.3d 1, 5 (D.C. Cir. 2002)).

³¹⁴⁰ *Long Island Power Auth. v. FERC*, 27 F.4th 705, 713–14 (D.C. Cir. 2022); *Old Dominion Elec. Coop. v. FERC*, 898 F.3d at 1261–63.

³¹⁴¹ Order No. 1000, 136 FERC ¶ 61,051 at P 637.

³¹⁴² *Id.* PP 647–648.

³¹⁴³ *Id.* P 660. See also *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87–88.

³¹⁴⁴ Order No. 1000, 136 FERC ¶ 61,051 at P 660. See also *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 87–88.

³¹⁴⁵ Order No. 1000, 136 FERC ¶ 61,051 at P 669.

³¹⁴⁶ *Id.* P 685.

Transmission Cost Allocation Methods comply with Order No. 1000 regional cost allocation principle (6), consistent with the request of some commenters,³¹⁴⁷ we find that reliability, economic, or public policy transmission facility types reflect a more siloed approach to regional transmission planning that is misaligned with our Long-Term Regional Transmission Planning reforms and would likely lead to the allocation of the costs of Long-Term Regional Transmission Facilities in a manner that is not at least roughly commensurate with estimated benefits.

1475. We clarify that this final order does not preclude the adoption of multiple Long-Term Regional Transmission Cost Allocation Methods, provided that the Long-Term Regional Transmission Cost Allocation Method that will apply to a Long-Term Regional Transmission Facility (or portfolio of such Facilities) is known before selection, *i.e.*, is an *ex ante* cost allocation method, and does not allocate costs by project type. We find that knowing the applicability of a Long-Term Regional Transmission Cost Allocation Method in advance is inherent to the definition of, and one of the primary reasons for, requiring transmission providers to include an *ex ante* cost allocation method in their OATTs. As such, transmission providers that choose to propose more than one Long-Term Regional Transmission Cost Allocation Method on compliance are required to make clear in their OATTs which Long-Term Regional Transmission Cost Allocation Method applies to which Long-Term Regional Transmission Facilities (*e.g.*, cost allocation methods that apply to Long-Term Regional Transmission Facilities above a certain voltage threshold or to Long-Term Regional Transmission Facilities located within a specific portion of a transmission planning region's footprint).³¹⁴⁸ However, we emphasize that any Long-Term Regional Transmission Cost Allocation Method that transmission providers propose, except for those that Relevant State Entities indicate that they agreed to and asked the transmission providers in their transmission planning region to file, must comply with Order No. 1000 regional cost allocation principles (1) through (5) and the other requirements of this final order.

1476. Regarding cost allocation methods resulting from a State

Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and asked transmission providers to file after the Engagement Period, the Commission has previously found that "Order No. 1000 allows market participants, including states, to negotiate voluntarily alternative cost sharing arrangements that are distinct from the relevant regional cost allocation method(s)." ³¹⁴⁹ Additionally, where transmission providers have proposed cost allocation methods corresponding to such voluntary arrangements, the Commission has held that it need not find that those cost allocation methods comply with Order No. 1000.³¹⁵⁰ Consistent with this precedent, we find that cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to and have asked transmission providers to file also qualify as voluntary alternative cost sharing arrangements and, accordingly, we decline to require those methods to adhere to the six Order No. 1000 regional cost allocation principles. However, those methods must still comply with the cost causation principle and any other legal requirements for cost allocation.

1477. We decline to adopt the NOPR proposal that required adherence to the six Order No. 1000 regional cost allocation principles because cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to are likely to facilitate agreement over development of such Long-Term Regional Transmission Facilities by, for example, making the Relevant State Entities more confident that customers in the state are receiving benefits at least roughly commensurate with their share of the cost of such facilities and by reducing the likelihood that selected Long-Term Regional Transmission Facilities cannot be constructed because they do not receive necessary state regulatory approvals. Affording additional flexibility for these methods

may encourage their use, which would facilitate the selection of more efficient or cost-effective Long-Term Regional Transmission Facilities. However, as described in the next section, we note that cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to must be just and reasonable and not unduly discriminatory or preferential and must allocate costs in a manner that is at least roughly commensurate with estimated benefits.³¹⁵¹

1478. ELCON and West Virginia Commission express concern that the NOPR's proposals for cost allocation methods, including requiring compliance with the six Order No. 1000 regional cost allocation principles, might not sufficiently recognize specific Public Policy Requirements as driving the needs for specific Long-Term Regional Transmission Facilities and, therefore, allow cost allocation methods that contradict precedent on cost causation. Similarly, Utah Division of Public Utilities asks that the Long-Term Regional Transmission Cost Allocation Method be required to use cost causation principles to determine what portion of Long-Term Regional Transmission Facilities are due to state policies when states or other stakeholders disagree on the cost allocation method due to differing renewable goals. We believe these concerns are misplaced and no further requirements are necessary. First, while state laws, regulations, and goals make up some of the drivers of Long-Term Transmission Needs, they do not comprise the entirety of those needs, as described in the Development of Long-Term Scenarios section of this final order. Second, as described below, all cost allocation methods for Long-Term Regional Transmission Facilities must allocate costs to transmission customers in a manner that is at least roughly commensurate with their estimated benefits. Third, for Long-Term Regional Transmission Cost Allocation Methods, except for those that Relevant State Entities indicate that they agreed to and asked the transmission providers in their transmission planning region to file, compliance with five of the Order No. 1000 regional cost allocation principles further safeguards against cost causation concerns; notably, principles (1) and (2) require that benefits received are at least roughly commensurate with costs paid and that costs may not be involuntarily allocated

³¹⁴⁷ Massachusetts Attorney General Initial Comments at 15, 21; Ørsted Initial Comments at 9.

³¹⁴⁸ We believe that this finding should address MISO's request that the final order not preclude applying different cost allocation methods to projects of the same type.

³¹⁴⁹ *State Voluntary Agreements to Plan & Pay for Transmission Facilities*, 175 FERC ¶ 61,225 at P 3 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 561, 724; Order No. 1000-A, 139 FERC ¶ 61,132 at PP 728–729).

³¹⁵⁰ See *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 142–143, *order on reh'g and compliance*, 147 FERC ¶ 61,128 at P 92; *ISO New England Inc.*, 143 FERC ¶ 61,150 at P 121; *Consol. Edison Co. of N.Y., Inc.*, 180 FERC ¶ 61,106, at PP 48–50 (2022).

³¹⁵¹ See, *e.g.*, *PPL Elec. Utils. Corp.*, 181 FERC ¶ 61,178 at P 33.

to those that do not benefit, respectively. Further, Order No. 1000 regional cost allocation principle (5), as well as the requirements in this final order to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities, ensures sufficient transparency for stakeholders to understand how the costs of selected Long-Term Regional Transmission Facilities will be allocated to transmission customers in relation to the benefits that they are forecasted to provide. Lastly, for cost allocation methods resulting from a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities have agreed to and asked transmission providers to file, we believe that states will have an opportunity to come to consensus on cost allocation methods that they perceive as allocating costs in a manner that is at least roughly commensurate with estimated benefits.

1479. Regarding Vermont Electric and Vermont Transco's concern regarding possible discrepancies between benefits received by small rural states and larger, more populated states, we believe that our requirement that all cost allocation methods for Long-Term Regional Transmission Facilities must allocate costs in a manner that is at least roughly commensurate with estimated benefits addresses this concern. Regarding OMS's, Louisiana Commission's, and Ohio Consumers' requests that the Commission adopt certain cost allocation principles distinct from the six Order No. 1000 regional cost allocation principles, the Commission did not propose adoption of any additional principles or that the six Order No. 1000 regional cost allocation principles be substituted for others. Accordingly, we find these requests beyond the scope of this final order. Additionally, in response to Exelon's request that the Commission clarify that the proposed State Agreement Process is supplementary to any previously accepted provisions for state agreement-based cost allocation,³¹⁵² we clarify that any State Agreement Process that the Commission accepts in compliance with this final order will apply to only Long-Term Regional Transmission Facilities, while any existing voluntary state cost allocation processes that the Commission has previously accepted apply to other transmission facilities and, thus, are unaltered by this final order.

C. Identification of Benefits Considered in Cost Allocation for Long-Term Regional Transmission Facilities

1. NOPR Proposal

1480. The Commission proposed to require transmission providers in each transmission planning region to identify on compliance the benefits they will use in *ex ante* Long-Term Regional Transmission Cost Allocation Methods associated with Long-Term Regional Transmission Planning, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand. The Commission proposed that as part of this compliance obligation, transmission providers must explain the rationale for using the benefits identified.³¹⁵³ The Commission also requested comment on whether the Commission should require that transmission providers account for the full list of benefits, as described in the Evaluation of the Benefits of Regional Transmission Facilities section above, in Long-Term Regional Transmission Planning, or whether no change to the benefits currently used in existing regional transmission planning processes is needed.³¹⁵⁴

1481. The Commission also proposed, for purposes of cost allocation, to require that transmission providers in each transmission planning region evaluate, as part of Long-Term Regional Transmission Planning, the benefits of regional transmission facilities over a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date of the transmission facilities.³¹⁵⁵

2. Comments

a. Agree With Proposal

1482. Some commenters agree with the NOPR proposal.³¹⁵⁶ NESCOE contends that it is critical that costs as well as benefits be clearly identified in connection with project evaluation.³¹⁵⁷

1483. Many commenters supporting the proposal emphasize the importance of flexibility and the lack of a proposed requirement in the NOPR to require that specific benefits be accounted for in cost

allocation.³¹⁵⁸ Dominion opposes making the NOPR's listed benefits mandatory for cost allocation because identifying and measuring them would be difficult and lead to disputes and litigation that would add to the costs, borne by consumers, of transmission development.³¹⁵⁹ NYISO states that considering the list of benefits in the NOPR in cost allocation would introduce significant complexity and create a burdensome and perhaps infeasible process.³¹⁶⁰ Xcel states that not all benefits need to be studied given that such study can be costly and add little value, and that the analysis of future benefits should balance uncertainties to ensure that it is not too speculative.³¹⁶¹

1484. Pacific Northwest Utilities and SERTP Sponsors argue that many of the NOPR's proposed benefits would work only in RTO/ISO transmission planning regions and are not appropriate in non-RTO/ISO regions.³¹⁶² Pacific Northwest Utilities state that several of the benefits listed in the NOPR do not benefit transmission providers and argue that—in non-RTO/ISO transmission planning regions, like NorthernGrid, where there is neither a single independent transmission system operator nor any single independent transmission provider through which to affect transmission rate impacts due to cost allocation—costs allocated to transmission providers must be based on benefits to the transmission provider, not benefits realized by others, such as generators and load-serving entities.³¹⁶³ California Municipal Utilities argue that requiring consideration of the list of benefits in the NOPR would not reflect the state and local nature of resource portfolio planning and would fail to account for the costs of such prescriptive measures and consumer protection against speculative

³¹⁵⁸ APPA Initial Comments at 46; Dominion Initial Comments at 45–46; Dominion Reply Comments at 6, 9; Exelon Initial Comments at 29–30 (citing NOPR, 179 FERC ¶ 61,028 at P 312 & n.516; *Midwest ISO Transmission Owners*, 373 F.3d at 1369); Louisiana Commission Initial Comments at 35–36; NARUC Initial Comments at 38; National Grid Initial Comments at 26–27; NYISO Initial Comments at 51–52; Pacific Northwest Utilities Initial Comments at 8–9; PPL Initial Comments at 28; SERTP Sponsors Initial Comments at 30–31; Southern Initial Comments at 27; Xcel Initial Comments at 12.

³¹⁵⁹ Dominion Reply Comments at 6–7.

³¹⁶⁰ NYISO Initial Comments at 52.

³¹⁶¹ Xcel Initial Comments at 12.

³¹⁶² Pacific Northwest Utilities Initial Comments at 8–10; SERTP Sponsors Initial Comments at 29–30.

³¹⁶³ Pacific Northwest Utilities Initial Comments at 9–10.

³¹⁵² Exelon Initial Comments at 27–28.

³¹⁵³ NOPR, 179 FERC ¶ 61,028 at P 326.

³¹⁵⁴ *Id.* P 327.

³¹⁵⁵ *Id.* P 228.

³¹⁵⁶ Avangrid Initial Comments at 29; California Energy Commission Initial Comments at 3; Idaho Power Initial Comments at 11; ITC Initial Comments at 30; NESCOE Initial Comments at 72; Northwest and Intermountain Initial Comments at 18–19.

³¹⁵⁷ NESCOE Initial Comments at 72.

projects.³¹⁶⁴ Louisiana Commission states that transmission providers and retail regulators should be allowed to develop and agree on an appropriate set of metrics to be used for cost allocation.³¹⁶⁵

1485. APPA argues that regional flexibility should include allowing transmission providers to demonstrate on compliance that the benefits that they use to allocate the costs of transmission projects identified through their existing regional transmission planning processes are sufficient for Long-Term Regional Transmission Planning.³¹⁶⁶ National Grid asserts that flexibility avoids the risk of a static list of benefits becoming outdated, citing as an example the growing numbers of distributed resources in New England driving the need for transmission-level upgrades in New England. National Grid claims that more granular (state-specific or even direct assignment) cost allocation is appropriate for such upgrades.³¹⁶⁷

1486. City of New Orleans Council, OMS, Louisiana Commission, and Michigan Commission argue that any benefit metrics should comply with OMS Cost Allocation Principle Committee Principle No. 2, which states that “[c]ost allocation should be as granular and accurate as possible. Benefit-cost analysis should use metrics that are quantifiable, capable of replication, non-duplicative, and forward-looking.”³¹⁶⁸ NARUC similarly asserts that transmission benefits must be verifiable and quantifiable to justify allocating costs to ratepayers.³¹⁶⁹ Likewise, Idaho Power, Pacific Northwest Utilities, and West Virginia Commission state that benefits must be quantifiable and justified, arguing that many benefits in the NOPR proposal would be difficult to quantify, a difficulty, Idaho Power and Pacific Northwest Utilities argue, exacerbated

by the proposed 20-year transmission planning horizon.³¹⁷⁰

1487. West Virginia Commission argues that use of these benefits allows for unfettered discretion by transmission providers to adopt cost allocation methods that do not meet the cost causation principle.³¹⁷¹

1488. Southern states that a cost allocation premised on an overly broad, non-quantifiable construction of benefits would likely exceed the Commission’s authority because there must be a correlation between the charges proposed and the expected benefits, as articulated by the courts.³¹⁷² Southern states that the Commission must apply the roughly commensurate standard by determining whether the benefits to the intended beneficiaries are quantifiable and spread evenly across a transmission planning region. Otherwise, Southern states, the Commission must compile a record based on substantial evidence to support the proposed allocation of costs.³¹⁷³ Dominion similarly cautions that assignment of costs requires more than generalized articulation of benefits and that the list of benefits in the NOPR are broadly defined and generalized.³¹⁷⁴

1489. Ohio Consumers state that the Commission should base the benefits attributable to Long-Term Regional Transmission Planning on the electrons to be delivered from generating facilities. Ohio Consumers point out that state consumer advocates disagree as to which benefits should be considered in cost allocation.³¹⁷⁵ Ohio Consumers argue that adopting a broad definition of benefits that includes state decarbonization plans and socialization of some portion of the associated costs across a transmission planning region would violate the Order No. 1000 regional cost allocation principles and the cost causation principle.³¹⁷⁶

1490. Pennsylvania Commission takes no position on requiring certain benefits to be accounted for in cost allocation, but states that the need for objective, well-defined, and measurable benefits

applies not only to transmission planning but also to cost allocation, noting that it is important that customers who pay the costs allocated to them agree that they are paying for real and appreciable benefits.³¹⁷⁷

b. Requests To Reflect the Full Breadth of Benefits in Cost Allocation Methods While Maintaining Flexibility

1491. Some commenters request that transmission providers reflect the full breadth of benefits in cost allocation methods for Long-Term Regional Transmission Facilities while also supporting flexibility.³¹⁷⁸ Vistra asserts that benefits considered in cost allocation should not be confined to a prescriptive list.³¹⁷⁹ NESCOE argues that the Commission should include a list of benefits in the final order as a required starting point and allow transmission providers to add or subtract benefits from the list on compliance following consultation with states in their transmission planning region.³¹⁸⁰

c. Disagree With Proposal, Mostly Require Benefits

1492. Some commenters disagree with the Commission’s proposal, arguing that the Commission should require transmission providers to account for a minimum set of benefits in cost allocation.³¹⁸¹ Indicated U.S. Senators and Representatives argue that unless all benefits and costs are incorporated into transmission planning and cost allocation, the result will be biased, resulting in unjust and unreasonable costs and cost allocation.³¹⁸² Acadia Center and CLF contend that failure to consider a minimum set of benefits could result in the failure to select transmission projects that would have benefited customers.³¹⁸³ Certain TDUs argue that guardrails should be put in place to require transmission providers to adequately define quantifiable benefits and to make transparent their method for identifying benefits; however, Certain TDUs contend that the

³¹⁶⁴ California Municipal Utilities Reply Comments at 5–6 (citing ACEG Initial Comments at 26–48, 50–51, 60–63).

³¹⁶⁵ Louisiana Commission Initial Comments at 35.

³¹⁶⁶ APPA Initial Comments at 46.

³¹⁶⁷ National Grid Initial Comments at 26–27.

³¹⁶⁸ City of New Orleans Council Initial Comments at 11; Louisiana Commission Initial Comments at 35–36; Michigan Commission Initial Comments at 9; OMS Initial Comments at 7–8, 14 (citing Organization of MISO States, Inc., *Organization of MISO States Statement of Principles: Cost Allocation for Long Range Transmission Planning Projects*, https://www.misostates.org/images/PositionStatements/OMS_Position_Statement_of_Principles_Cost_Allocation_for_LRTPs.pdf).

³¹⁶⁹ NARUC Initial Comments at 25, 38.

³¹⁷⁰ Idaho Power Initial Comments at 11; Pacific Northwest Utilities Initial Comments at 6–9; West Virginia Commission Reply Comments at 4.

³¹⁷¹ West Virginia Commission Reply Comments at 4.

³¹⁷² Southern Initial Comments at 28–30 (citing *Pac. Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1321 (D.C. Cir. 2004)).

³¹⁷³ *Id.* at 29–30 (citing *ICC v. FERC I*, 576 F.3d at 476–77; *Ill. Com. Comm’n v. FERC*, 721 F.3d 764, 777 (7th Cir. 2013) (*ICC v. FERC II*); *ICC v. FERC III*, 756 F.3d at 564–565).

³¹⁷⁴ Dominion Initial Comments at 43–44.

³¹⁷⁵ Ohio Consumers Reply Comments at 10.

³¹⁷⁶ Ohio Consumers Reply Comments at 11 (citing DC and MD Offices of People’s Counsel Initial Comments at 31, 34, 38–39).

³¹⁷⁷ Pennsylvania Commission Initial Comments at 11.

³¹⁷⁸ APPA Initial Comments at 45–46; Massachusetts Attorney General Initial Comments at 21; NESCOE Initial Comments at 72; Vistra Initial Comments at 15.

³¹⁷⁹ Vistra Initial Comments at 15.

³¹⁸⁰ NESCOE Initial Comments at 43, 72.

³¹⁸¹ Acadia Center and CLF Initial Comments at 16–19; Certain TDUs Reply Comments at 2–3; Indicated U.S. Senators and Representatives Initial Comments at 2; U.S. Climate Alliance Initial Comments at 2; U.S. Senators Supplemental Comments at 2.

³¹⁸² Indicated U.S. Senators and Representatives Initial Comments at 2.

³¹⁸³ Acadia Center and CLF Initial Comments at 16–19.

Commission should require transmission providers to account for, at minimum, production cost savings and avoided or deferred reliability transmission facilities and aging transmission infrastructure replacement, as may be refined by transmission planning regions as necessary.³¹⁸⁴ US Climate Alliance states that each transmission planning region could determine additional categories of benefits most relevant to them.³¹⁸⁵

1493. Other commenters that disagree with the Commission's proposal similarly argue for a required minimum set of benefits, but argue that the Commission should require transmission providers to account for the full list of 12 benefits in the NOPR.³¹⁸⁶ ACEG and PIOs state that it would be unjust and unreasonable for transmission providers to allocate costs in a manner that ignores certain benefits or fails to provide a full accounting of those benefits, including, PIOs assert, cost allocation agreed to by states.³¹⁸⁷ PIOs further argue that allowing transmission providers to agree to a cost allocation method that does not reflect all quantifiable benefits would re-introduce the risk of free ridership.³¹⁸⁸

1494. Clean Energy Buyers state that they support the Commission requiring each transmission provider to either adopt the benefits identified by the Commission to be used for cost allocation for Long-Term Regional Transmission Facilities or demonstrate why the exclusion of any such benefit(s) is just and reasonable. However, Clean Energy Buyers also recommend that the Commission consider how the factors required for Long-Term Scenarios will translate into benefits and ensure that there is no double-counting of benefits.³¹⁸⁹

1495. Southwestern Power Group states that existing regional cost allocation methods do not account for the range of benefits that regional transmission expansion can provide. Consequently, Southwestern Power Group argues, the costs of regional transmission projects are allocated to too few of the beneficiaries, discouraging the development of regional transmission projects.³¹⁹⁰

Environmental Groups argue that the Commission must ensure that any cost allocation method agreed to by states complies with the beneficiary-pays principle by showing that the method considers all quantifiable benefits of transmission.³¹⁹¹

1496. SPP states that its regional cost allocation method does not quantify the specific benefits of transmission facilities within each planning assessment but instead analyzes the benefits and costs of facilities approved in multiple assessments in a comprehensive manner. SPP states that potential inequities are not appropriately quantified in a single regional planning assessment cycle because potential imbalances in one cycle may be offset in later cycles or changed because of topology. SPP emphasizes that quantification of whether benefits of transmission facilities are roughly commensurate with allocated costs should be performed through multiple transmission planning cycles that evaluate project portfolios, citing SPP's Highway-Byway cost allocation method as an example.³¹⁹²

d. Alignment of Benefits Between Transmission Planning and Cost Allocation

1497. Various commenters proffer arguments as to whether benefits used in the evaluation and selection of Long-Term Regional Transmission Facilities must align with the benefits used in cost allocation. For example, SERTP Sponsors state that there could be differences between the types of benefits used for evaluation and selection and those used for cost allocation, asserting that benefits used in cost allocation must be measured in a consistent and objective manner to limit disputes.³¹⁹³

1498. Some commenters argue that the benefits used in the evaluation and selection of Long-Term Regional Transmission Facilities should closely align with, but need not be the same as, those used in cost allocation.³¹⁹⁴ For example, Clean Energy Associations state that close alignment does not preclude regional variation and points to MISO's Multi-Value Projects' and SPP's Highway/Byway projects' cost allocation methods.³¹⁹⁵

1499. Some commenters argue that the same set of benefits used in transmission planning should be used in cost allocation.³¹⁹⁶ DC and MD Offices of People's Counsel and the New Jersey Commission link such a requirement with the beneficiary-pays principle.³¹⁹⁷ New Jersey Commission states that enforcing the beneficiary-pays principle based on all of a transmission project's quantified benefits is necessary to avoid free-rider problems that could arise, especially in the State Agreement Process.³¹⁹⁸ Additionally, New Jersey Commission states, the policy of preventing states from involuntarily bearing the costs of others' policies must not require states to always pay the full cost of any transmission solution that supports their public policies or prevent states from committing to paying more than what they perceive to be their fair share to overcome disagreements over who will benefit.³¹⁹⁹ Similarly, BP recommends requiring that those benefitting from transmission facilities that meet policy objectives, but without similar policies themselves, be allocated an appropriate share of costs to avoid free ridership.³²⁰⁰

1500. Massachusetts Attorney General states that *ex ante* cost allocation methods should reflect the same benefits considered in Long-Term Regional Transmission Planning and not consider benefits in silos.³²⁰¹ Ørsted similarly supports a requirement that transmission providers adopt cost allocation methods that recognize the full breadth of benefits that transmission facilities provide.³²⁰²

1501. PIOs argue that cost allocation is necessarily implicated in the NOPR's preliminary finding that failure to consider a broader set of benefits and beneficiaries of transmission facilities may result in unjust, unreasonable, and unduly discriminatory or preferential rates, reasoning that cost allocation cannot be based on unlawful

³¹⁹⁶ DC and MD Offices of People's Counsel Initial Comments at 34; Fervo Reply Comments at 2–3; New Jersey Commission Initial Comments at 18–23; SEIA Initial Comments at 24; Vermont Electric and Vermont Transco Initial Comments at 4; WATT Coalition Initial Comments at 8.

³¹⁹⁷ DC and MD Offices of People's Counsel Initial Comments at 34 (citing *ICC v. FERC I*, 576 F.3d 470; *ICC v. FERC II*, 721 F.3d 764; *ICC v. FERC III*, 756 F.3d 556); New Jersey Commission Initial Comments at 18–23 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d at 1262–63; *Entergy Ark. v. FERC*, 40 F.4th 689, 701 (D.C. Cir. 2022)).

³¹⁹⁸ New Jersey Commission Initial Comments at 18.

³¹⁹⁹ *Id.* at 21–23.

³²⁰⁰ BP Initial Comments at 9–12.

³²⁰¹ Massachusetts Attorney General Initial Comments at 21.

³²⁰² Ørsted Initial Comments at 9.

³¹⁸⁴ Certain TDUs Reply Comments at 2–3.

³¹⁸⁵ U.S. Climate Alliance Initial Comments at 2.

³¹⁸⁶ ACEG Initial Comments at 60; Clean Energy Associations Initial Comments at 20–21, 34; DC and MD Offices of People's Counsel Initial Comments at 20, 34; PIOs Initial Comments at 64–65.

³¹⁸⁷ ACEG Initial Comments at 60–61 (citing *ICC v. FERC I*, 576 F.3d at 477); PIOs Initial Comments at 65; PIOs Reply Comments at 3.

³¹⁸⁸ PIOs Initial Comments at 65.

³¹⁸⁹ Clean Energy Buyers Initial Comments at 30.

³¹⁹⁰ Southwestern Power Group Initial Comments at 14–15.

³¹⁹¹ Environmental Groups Supplemental Comments at 2.

³¹⁹² SPP Initial Comments at 31.

³¹⁹³ SERTP Sponsors Initial Comments at 30–31.

³¹⁹⁴ Clean Energy Associations Initial Comments at 34; Cypress Creek Reply Comments at 14–15; Ørsted Initial Comments at 9.

³¹⁹⁵ Clean Energy Associations Initial Comments at 34–35.

identification of benefits and beneficiaries.³²⁰³

e. Additional Benefits or Suggestions for Refinement

1502. DC and MD Offices of People's Counsel recommend that the Commission allow Relevant State Entities to propose additional benefit categories for evaluation and to consent to the allocation of costs that align with these additional benefits. At a minimum, DC and MD Offices of People's Counsel argue, costs should be allocated to the benefitting Relevant State Entities.³²⁰⁴

1503. California Energy Commission recommends that transmission providers be required to consider equity and environmental justice in the calculation of benefits, including economic, health, and social benefits to disadvantaged communities.³²⁰⁵ WE ACT recommends that the Commission include non-energy benefits like pollution reduction, health, jobs, and local economic development in the list of benefits that transmission providers should be required to utilize in identifying and evaluating Long-Term Regional Transmission Facility need, selection, and cost allocation.³²⁰⁶

1504. Louisiana Commission states that the Commission should permit transmission providers to consider allocations to all cost causers and beneficiaries, including generators.³²⁰⁷ *Vistra* argues that if achieving voluntary corporate and utility clean energy goals is factored into demand driving the need for an upgrade, then the costs of such upgrades should not be assigned to regional load.³²⁰⁸

3. Commission Determination

1505. We decline to adopt the NOPR proposal to require transmission providers to identify on compliance the benefits that they will use in Long-Term Regional Transmission Cost Allocation Methods, how they will calculate those benefits, and how the benefits will reasonably reflect the benefits of regional transmission facilities to meet identified transmission needs driven by changes in the resource mix and demand.

1506. Instead, as we discuss above in the Long-Term Regional Transmission Facility Cost Allocation Compliance

with the Existing Six Order No. 1000 Regional Cost Allocation Principles section, we require transmission providers in each transmission planning region to demonstrate on compliance that the required Long-Term Regional Transmission Cost Allocation Method(s) that Relevant State Entities have *not* indicated that they agree to comply with Order No. 1000 regional transmission cost allocation principles (1) through (5) and do not allocate costs by project type (*i.e.*, reliability, economic, or transmission needs driven by Public Policy Requirements). While we do not require that cost allocation methods resulting from State Agreement Processes or Long-Term Regional Transmission Cost Allocation Methods that Relevant States Entities indicate they agreed to, must comply with any of the Order No. 1000 regional cost allocation principles, if filed with the Commission, transmission providers must nonetheless demonstrate that either of these types of cost allocation methods will allocate costs in a manner at least roughly commensurate with estimated benefits.³²⁰⁹ We do not require that any particular benefit used in the evaluation and selection of Long-Term Regional Transmission Facilities be reflected in a Long-Term Regional Transmission Cost Allocation Method filed with the Commission. We adopt this modified approach to the relationship of benefits used in Long-Term Regional Transmission Planning and Long-Term Regional Transmission Cost Allocation Methods because it provides transmission providers with flexibility to propose a Long-Term Regional Transmission Cost Allocation Method(s), allowing for negotiation in the Engagement Period, which we believe will increase the chances that Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective regional transmission solution will be developed. At the same time, the requirements in this final order to disclose estimates of the benefits of selected Long-Term Regional Transmission Facilities will provide transparency and help to ensure a cost allocation is just and reasonable.

1507. We note that this flexible approach is consistent with the approach that the Commission took in Order No. 1000 and in subsequent orders on transmission providers' Order No. 1000 compliance filings, where the Commission allowed a wide variety of cost allocation methods and did not require that such methods specifically account for all benefits used in

evaluation and selection processes.³²¹⁰ The cost allocation method for MISO's Multi-Value Projects and the SPP Highway/Byway cost allocation method are examples that reflect the flexibility that transmission providers have had in adopting cost allocation methods suited to their circumstances and that may not have been possible under a less flexible approach.

1508. The one exception to that flexibility, however, is the second component of our compliance requirement, that transmission providers must not allocate costs based on project types; namely, reliability, economic, or Public Policy Requirements needs-driven cost allocation methods. As described in the Long-Term Regional Transmission Facility Cost Allocation Compliance with Existing Six Order No. 1000 Regional Cost Allocation Principles section, we adopt this requirement because permitting such project-type-limited cost allocation methods for Long-Term Regional Transmission Facilities would be inconsistent with the long-term, forward-looking, more comprehensive regional transmission planning that we require in this final order. As we note above in the Need for Reform section, allocating costs based on these project types would result in transmission providers undertaking investments in relatively inefficient or less cost-effective transmission infrastructure, the costs of which are ultimately recovered through Commission-jurisdictional rates. Allocating costs based on these project types could, for example, encourage the selection of transmission facilities based on either their economic or reliability benefits alone rather than based on an evaluation of the wider range of benefits that they may provide. This dynamic results in, among other things, transmission customers paying more than is necessary or appropriate to meet their transmission needs, customers forgoing benefits that outweigh their costs, or some combination thereof, which results in less efficient or cost-effective transmission investments. We further find that permitting the use of such project-type-limited cost allocation methods for Long-Term Transmission Facilities would not allocate costs in a manner that is at least roughly commensurate to estimated benefits.

1509. We decline to adopt the NOPR proposal to require transmission providers to evaluate benefits over a 20-year time horizon for Long-Term Regional Transmission Planning for

³²⁰³ PIOs Initial Comments at 71.

³²⁰⁴ DC and MD Offices of People's Counsel Initial Comments at 34.

³²⁰⁵ California Energy Commission Initial Comments at 3.

³²⁰⁶ WE ACT Initial Comments at 5.

³²⁰⁷ Louisiana Commission Initial Comments at 32.

³²⁰⁸ *Vistra* Initial Comments at 21–22.

³²⁰⁹ See *ICC v. FERC I*, 576 F.3d at 477; *ICC v. FERC III*, 756 F.3d at 564.

³²¹⁰ Order No. 1000, 136 FERC ¶ 61,051 at PP 560, 624.

purposes of cost allocation. Given our decision to not require transmission providers to explain the benefits that they are using in cost allocation for Long-Term Regional Transmission Facilities, we believe this proposal is moot.

1510. We acknowledge New Jersey Commission's concern that permissive state-negotiated cost allocation could result in free riders. However, we note that, even for cost allocation methods filed pursuant to a State Agreement Process and Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed, the costs allocated in accordance with such methods must be, as noted above, at least roughly commensurate with estimated benefits consistent with legal precedent. On compliance with this final order, the Commission will evaluate whether any cost allocation method agreed to pursuant to a State Agreement Process, or Long-Term Regional Transmission Cost Allocation Methods that Relevant State Entities indicate that they have agreed to, and filed with the Commission, allocates the costs of Long-Term Regional Transmission Facilities in a manner that is at least roughly commensurate with the estimated benefits. Further, we believe that New Jersey Commission's concern is reduced by our modification to the NOPR proposal to require transmission providers to file a Long-Term Regional Transmission Cost Allocation Method that must be used where a State Agreement Process fails to result in agreement; to the extent Relevant State Entities do not agree to a cost allocation method through the State Agreement Process, the transmission provider's *ex ante* Long-Term Regional Transmission Cost Allocation Method will apply.

1511. Given our modification to the NOPR proposal to not require transmission providers to identify on compliance the benefits that they will use in Long-Term Regional Transmission Cost Allocation Methods, we find moot APPA's request that regional flexibility should include allowing transmission providers to demonstrate on compliance that their existing benefits used for cost allocation of transmission projects identified through their existing regional transmission planning processes are sufficient for Long-Term Regional Transmission Planning.³²¹¹

1512. With respect to the comments of City of New Orleans Council, OMS,

Louisiana Commission, and Michigan Commission arguing that any benefit metrics should comply with OMS Cost Allocation Principle Committee Principle No. 2,³²¹² which states that "[c]ost allocation should be as granular and accurate as possible,"³²¹³ we note that the flexibility we provide as to the consideration of benefits in cost allocation does not prevent transmission providers in a particular transmission planning region from adopting a more granular approach.

1513. With respect to Southern and Dominion's assertions that the Commission must ensure that costs are allocated in a manner that is at least roughly commensurate with benefits by conducting its evaluation of proposed cost allocation methods in a particular manner,³²¹⁴ we reiterate that we will apply existing Commission and judicial precedent, including that cited by Dominion and Southern, in our evaluation of any proposed cost allocation methods for Long-Term Regional Transmission Facilities. With respect to Louisiana Commission's assertion that the cost allocation process should be allowed to consider allocations to all cost causers and beneficiaries, including generators,³²¹⁵ we continue to adhere to the flexibility we provided in Order No. 1000–A. In that order, we found that with respect to generators being identified as beneficiaries and ultimately responsible for costs, just as each transmission planning region retains the flexibility to define benefit and beneficiary, the public utility transmission providers in each transmission planning region, in consultation with their stakeholders, may consider proposals to allocate costs directly to generators as beneficiaries that could be subject to regional or interregional cost allocation. However, we also found that any effort to do so must not be inconsistent with the generator interconnection process under Order No. 2003 because, as we stated in Order No. 1000, the generator interconnection process and interconnection cost recovery were outside the scope of that rulemaking.³²¹⁶

³²¹² City of New Orleans Council Initial Comments at 11; Louisiana Commission Initial Comments at 35–36; Michigan Commission Initial Comments at 9; OMS Initial Comments at 7–8, 14.

³²¹³ OMS Initial Comments at 7–8.

³²¹⁴ Southern Initial Comments at 29–30 (citing *ICC v. FERC I*, 576 F.3d at 476–77; *ICC v. FERC II*, 721 F.3d at 777; *ICC v. FERC III*, 756 F.3d at 564–565); Dominion Initial Comments at 43–44 (citing *ICC v. FERC I*, 576 F.3d at 477).

³²¹⁵ Louisiana Commission Initial Comments at 32.

³²¹⁶ Order No. 1000–A, 139 FERC ¶ 61,132 at P 680. While interconnection customers may

1514. We find Pacific Northwest Utilities' assertion that costs allocated to transmission providers in non-RTO/ISO transmission planning regions, like NorthernGrid, must be based on benefits to the transmission provider, not benefits realized by others, such as generators and load-serving entities,³²¹⁷ to be misplaced, as nothing in this final order requires that only transmission providers in non-RTO/ISO transmission planning regions bear the ultimate responsibility for the costs of Long-Term Regional Transmission Facilities. We recognize that, in the absence of a single regional transmission provider who can recover the costs of Long-Term Regional Transmission Facilities on behalf of its transmission-owning members from all of its transmission customers in its transmission planning region, transmission providers in non-RTO/ISO regions require alternative arrangements to allocate and recover the costs of Long-Term Regional Transmission Facilities from the transmission customers that benefit from them. We expect that in non-RTO/ISO transmission planning regions, as is the case with Order No. 1000 regional transmission planning and cost allocation processes today,³²¹⁸ transmission providers will establish arrangements to implement the cost allocation methods for Long-Term Regional Facilities and recover the costs of such facilities from the transmission customers that benefit from them.

1515. Some commenters advocate for accounting for public policy benefits in cost allocation methods for Long-Term Regional Transmission Facilities.³²¹⁹ Although we are not requiring transmission providers to account for public policy benefits in cost allocation methods for Long-Term Regional Transmission Facilities, we are also not foreclosing the possibility that transmission providers and stakeholders may seek to account for certain public

voluntarily fund the cost of, or a portion of the cost of, a Long-Term Regional Transmission Facility as discussed in the Evaluation and Selection of Long-Term Regional Transmission Facilities section, this process is distinct from allocating costs to generators under the Long-Term Regional Transmission Cost Allocation Method, as the Louisiana Commission appears to contemplate.

³²¹⁷ Pacific Northwest Utilities Initial Comments at 9–10.

³²¹⁸ See e.g., *Duke Energy Carolinas, LLC*, 147 FERC ¶ 61,241 at P 453; *Pub. Serv. Co. of Colo.*, 142 FERC ¶ 61,206 at P 314.

³²¹⁹ See e.g., California Energy Commission Initial Comments at 3 (recommending that equity and environmental justice benefits be accounted for in cost allocation, including economic, health, and social benefits to disadvantaged communities); WE ACT Initial Comments at 5 (recommending the following benefits be accounted for in cost allocation: pollution reduction, health, jobs, and local economic development).

³²¹¹ APPA Initial Comments at 46. We also discuss related concerns in the Cost Allocation for Long-Term Transmission Facilities section, above.

policy benefits when developing Long-Term Regional Transmission Cost Allocation Methods. We believe that states are well-positioned to value the benefits of achieving their respective public policy goals, consistent with past precedent in which we have affirmed the use of public policy benefits in regional transmission planning cost allocation,³²²⁰ and they or other stakeholders can similarly do so through engagement with transmission providers in their efforts to develop Long-Term Regional Transmission Cost Allocation Methods. In addition, to the extent states believe that a particular Long-Term Regional Transmission Facility would help achieve their public policy goals, we note our adoption in the Evaluation and Selection of Long-Term Regional Transmission Facilities section of this final order of opportunities for Relevant State Entities to voluntarily fund a portion of the cost of a Long-Term Regional Transmission Facility so that the facility can qualify for selection.³²²¹ The rule, consistent with the cost causation principle, does not allow allocation of costs based on benefits to entities that do not receive benefits or receive only trivial benefits in relationship to costs of those transmission facilities.³²²²

³²²⁰ As noted in the Evaluation of the Benefits of Regional Transmission Facilities section, RTOs/ISOs that have used some form of public policy benefit in regional transmission planning include PJM and NYISO. Although explicitly *not* part of PJM's Order No. 1000 regional transmission planning, PJM uses a State Agreement Approach to allow the development of public policy projects. See *PPL Elec. Utils. Corp.*, 181 FERC ¶ 61,178 at P 33 (finding that "allocating the costs of the New Jersey [State Agreement Approach] Projects on a load-ratio share basis to all New Jersey customers is roughly commensurate with the benefits provided by those projects"). NYISO provides for cost allocations developed by the New York State Public Service Commission for transmission projects developed to meet public policy needs. See *Consol. Edison Co. of N.Y., Inc.*, 180 FERC ¶ 61,106 at P 50 (finding that a volumetric load-ratio share cost allocation for certain local transmission upgrades was appropriate because the projects "benefit customers throughout the state insofar as they facilitate compliance with the New York State climate and renewable energy goals as required by New York State law and have been determined by the NYPSC to be necessary to meet such obligation").

³²²¹ *Supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

³²²² See *Coal. of MISO Transmission Customers v. FERC*, 45 F.4th 1004, 1009 (D.C. Cir. 2022) ("The cost-causation principle requires that 'the cost of transmission facilities be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.'") (cleaned up) (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d at 53); *ICC v. FERC I*, 576 F.3d at 477.

D. Miscellaneous Cost Allocation Comments and Proposals

1. Comments

1516. Some commenters discuss the appropriate time frame for cost allocation for Long-Term Regional Transmission Facilities. Dominion states that costs should not be allocated until closer in time to when a transmission project will be built and beneficiaries identified rather than when the Long-Term Regional Transmission Facilities are identified.³²²³ Ohio Consumers state that cost allocation decisions must be made on the basis of current or near-term transmission needs, and the Commission should not require subsidization for transmission lines on the theory that the line may be needed to serve future generation.³²²⁴ OMS supports a requirement that transmission providers identify beneficiaries of transmission projects before any costs are allocated.³²²⁵

1517. Acadia Center and CLF state that the Commission should expand its cost allocation proposals to encompass interregional transmission planning and the generator interconnection processes.³²²⁶

1518. Some commenters stress the importance of cost containment oversight by the Commission. Joint Commenters support a cost management framework overseen by the Commission ensuring that the costs and benefits on which transmission projects are initially approved for cost allocation remain within initially contemplated parameters.³²²⁷ State Water Contractors assert that the need for cost containment is acute for consumers in California, asserting that the CAISO high voltage transmission access charge has increased nearly 136% over the last decade. State Water Contractors argue that as increases in transmission costs have a direct impact on the cost of water delivery and treatment and given that water and energy are particularly intertwined in California, cost containment and regional flexibility are essential components to the justness and reasonableness of any final order.³²²⁸

1519. Ohio Consumers state that the Commission should require that the transmission providers implementing any Long-Term Regional Transmission

³²²³ Dominion Initial Comments at 42.

³²²⁴ Ohio Consumers Initial Comments at 19.

³²²⁵ OMS Initial Comments at 9.

³²²⁶ Acadia Center and CLF Initial Comments at 17.

³²²⁷ Joint Commenters Reply Comments at 1.

³²²⁸ State Water Contractors Reply Comments at 2–3.

Planning requirements give appropriate consideration to public grants and other external sources of funding in any cost allocation processes, adding that transmission providers should first seek public grants prior to charging customers, because infrastructure funds must be accounted for, or else they would distort cost allocation processes.³²²⁹

1520. NextEra renews its request for the Commission to initiate a new rulemaking to prohibit regional allocation of the costs of transmission projects developed pursuant to an incumbent transmission owner's exercise of state right-of-first-refusal rights and require the direct assignment of such costs to customers in the incumbent transmission owner's zone.³²³⁰

2. Commission Determination

1521. We decline to adopt a particular time frame for determining the cost allocation for a Long-Term Regional Transmission Facility, as requested by Dominion, Ohio Consumers, and OMS. We believe that imposing a standardized time frame to determine cost allocation is unnecessary and could impede the regional flexibility that we provide to transmission providers under this final order. However, as discussed above in the Long-Term Regional Transmission Facility Cost Allocation Compliance with the Existing Six Regional Cost Allocation Principles section, if only a Long-Term Regional Transmission Cost Allocation Method is available for a particular Long-Term Regional Transmission Facility (or portfolio of such Facilities), the determination of the applicable cost allocation must occur by or before its selection.

1522. We find Acadia Center and CLF's assertion that the Commission should expand its cost allocation proposals to encompass interregional transmission planning and the generator interconnection processes to be outside the scope of this proceeding, as is NextEra's request for the Commission to initiate a new rulemaking to prohibit regional allocation of the costs of transmission projects developed pursuant to an incumbent transmission owner's exercise of a state right of first refusal and require the direct assignment of such costs to customers in the incumbent transmission owner's zone. These suggestions are beyond the scope of the Commission's NOPR proposals and we believe that the record

³²²⁹ Ohio Consumers Reply Comments at 15 (citing Infrastructure Investment and Jobs Act of 2021, Public Law 117–58, 135 Stat 429).

³²³⁰ NextEra Reply Comments at 26.

in this proceeding is insufficient to proceed with them.

1523. We also find outside the scope of this proceeding various commenters' statements regarding cost containment. We note that the Commission is examining issues related to transmission planning and cost containment in other proceedings.³²³¹

VII. Construction Work in Progress Incentive

A. NOPR Proposal

1524. In the NOPR, the Commission proposed to not permit transmission providers to take advantage of the allowance for inclusion of 100% of Construction Work In Progress (CWIP) costs in rate base (CWIP Incentive) for Long-Term Regional Transmission Facilities.³²³² The Commission noted that transmission providers may still accrue carrying costs incurred during the pre-construction or construction phase as Allowance for Funds Used During Construction (AFUDC) and only recover those costs from customers after the project is in service, in accordance with generally accepted utility accounting principles for AFUDC.³²³³ The Commission explained that this proposal would not affect Commission policy and regulations established before Order No. 679.³²³⁴

B. Comments

1. Interest in the NOPR Proposal

1525. Many commenters support the Commission's NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being

eligible for the CWIP Incentive and generally support permitting cost recovery instead through AFUDC, agreeing that extending the CWIP Incentive to Long-Term Regional Transmission Facilities would expose ratepayers to risks and cost burdens by requiring them to pay for Long-Term Regional Transmission Facilities that receive the incentive prior to those facilities being placed into service.³²³⁵

1526. California Commission and New England Systems argue that there is no evidence that any of the incentives established under FPA section 219, including the CWIP Incentive, have spurred investment in transmission infrastructure.³²³⁶ California Commission argues that there was a great need to develop new transmission to bolster reliability and alleviate congestion when the CWIP Incentive was first introduced in Order No. 679, but that the prior decline in transmission investment has since been reversed.³²³⁷ Further, California Commission argues that an inability to receive the CWIP Incentive would not present a barrier to entry for transmission development,³²³⁸ stating that disallowing the CWIP Incentive for Long-Term Regional Transmission Facilities would affect incumbent and nonincumbent transmission developers equally, and that developers could continue to seek the CWIP Incentive for economic and reliability transmission

projects.³²³⁹ Louisiana Commission states that if an independent transmission developer or utility has won a competitive bidding process to construct transmission facilities, that entity should have the financial wherewithal to finance the project without a loan from ratepayers.³²⁴⁰

1527. Several commenters assert that the CWIP Incentive shifts risks to customers.³²⁴¹ Pennsylvania Commission, Large Public Power, and Resale Iowa argue that allowing the CWIP Incentive could substantially increase the risk of customers paying for transmission facilities that are never built and from which they derive no benefit, leading to rates that are unjust and unreasonable.³²⁴² NARUC, New England Systems, and Virginia Attorney General agree with the proposed reform because it better aligns risk and reward between shareholders and customers with respect to Long-Term Regional Transmission Facilities.³²⁴³

1528. Several other commenters state that the longer the transmission planning horizon, the higher the risk that resulting transmission facilities will not be needed, which may result in stranded costs.³²⁴⁴ For this reason, Industrial Customers state that shifting risks from transmission developers to customers is particularly problematic for Long-Term Regional Transmission Facilities.³²⁴⁵ Dominion states that it does not take a position on the proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, but nevertheless asserts that shifting the risk for long-term transmission projects to transmission providers will help ensure that only those long-term projects that are "confidently needed" will be developed. However, for states that may

³²³¹ See, e.g., Supplemental Notice of Technical Conference, Transmission Planning and Cost Management, Docket No. AD22-8-000 (Oct. 4, 2022).

³²³² NOPR, 179 FERC ¶ 61,028 at PP 328–329 n.522–523, 525–527 (citing Order No. 679, 71 FR 43294 (July 31, 2006), 116 FERC ¶ 61,057 at PP 9, 116–117, n.70). The Commission stated that the Commission has also provided that any public utility engaged in the sale of electric power for resale can file to include in rate base up to 50% of CWIP, subject to limitations. *Construction Work in Progress for Pub. Utils.; Inclusion of Costs in Rate Base*, Order No. 298, 48 FR 24323 (June 1, 1983), FERC Stats. & Regs. ¶ 30,455 (1983) (cross-referenced at 23 FERC ¶ 61,224), *order on reh'g*, 25 FERC ¶ 61,023 (1983). NOPR, 179 FERC ¶ 61,028 at P 329 n.524.

³²³³ NOPR, 179 FERC ¶ 61,028 at P 333.

³²³⁴ *Id.* P 333 n.530. There, the Commission stated that public utility transmission providers would still be allowed to request 50% CWIP in rate base, as is permitted pursuant to 18 CFR 35.25(c)(3), subject to an FPA section 205 filing detailing how the request meets the requirements of Order No. 298. The Commission believed that the ability to include 50% CWIP in rate base, if requested and granted, reflects a more reasonable sharing of risks and benefits than the CWIP Incentive for Long-Term Regional Transmission Facilities given the greater uncertainty inherent in Long-Term Regional Transmission Planning, as proposed in this NOPR.

³²³⁵ American Municipal Power Initial Comments at 34; APPA Initial Comments at 6, 46–47; California Commission Initial Comments at 58; California Water Initial Comments at 19–20; Clean Energy Buyers Initial Comments at 30–31; ELCON Initial Comments at 19; Industrial Customers Initial Comments at 24–26; Joint Consumer Advocates Initial Comments at 14; Kentucky Commission Chair Chandler Initial Comments at 4; Large Public Power Initial Comments at 41–42; Louisiana Commission Initial Comments at 36; Massachusetts Attorney General Initial Comments at 23; NARUC Initial Comments at 54–55; NASUCA Initial Comments at 8–9; NESCOE Initial Comments at 73; Nevada Commission Initial Comments at 14; North Carolina Commission and Staff Initial Comments at 17–18; NRG Initial Comments at 21–22; Ohio Commission Federal Advocate Initial Comments at 15–16; Ohio Consumers Initial Comments at 29; Pennsylvania Commission Initial Comments at 17; PJM States Initial Comments at 13; Resale Iowa Initial Comments at 2, 12–13; Six Cities Initial Comments at 11; State Agencies Initial Comments at 24; TAPS Initial Comments at 5, 27–29; Transmission Dependent Utilities Initial Comments at 2–4; Virginia Attorney General Initial Comments at 4–6.

³²³⁶ California Commission Reply Comments at 11–12; New England Systems Reply Comments at 15–16.

³²³⁷ California Commission Reply Comments at 8–10 (citing US DOE, *National Electric Transmission Congestion Study*, at 21 (Sept. 2020), <https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf>).

³²³⁸ *Id.* at 19–20 (citing CAISO Initial Comments at 44).

³²³⁹ *Id.*

³²⁴⁰ Louisiana Commission Initial Comments at 36.

³²⁴¹ California Commission Reply Comments at 14; Large Public Power Initial Comments at 41; Louisiana Commission Initial Comments at 36; NARUC Initial Comments at 55–56; New England Systems Reply Comments at 15; Ohio Commission Federal Advocate Initial Comments at 16; Pennsylvania Commission Initial Comments at 17; Resale Iowa Initial Comments at 12–13; Virginia Attorney General Reply Comments at 2.

³²⁴² Large Public Power Initial Comments at 41; Pennsylvania Commission Initial Comments at 17; Resale Iowa Initial Comments at 12–13.

³²⁴³ NARUC Initial Comments at 55–56; New England Systems Reply Comments at 15 (citing NARUC Initial Comments at 56); Virginia Attorney General Reply Comments at 2 (citing NARUC Initial Comments at 55).

³²⁴⁴ Clean Energy Buyers Reply Comments at 10–11; Dominion Initial Comments at 53–54; Industrial Customers Reply Comments at 9; Transmission Dependent Utilities Reply Comments at 4; Virginia Attorney General Reply Comments at 3.

³²⁴⁵ Industrial Customers Reply Comments at 9.

allow or require the inclusion of the CWIP Incentive in rate base, Dominion states that the Commission should allow for deference to the state cost recovery structure.³²⁴⁶

1529. Several commenters suggest that such reform may mitigate certain risks of the transmission provider overbuilding the system.³²⁴⁷ For example, Massachusetts Attorney General and North Dakota Commission state that the Commission's proposed limit on the CWIP Incentive would provide ratepayers greater protection from financing inefficient or over-built regional transmission projects.³²⁴⁸ New England Systems argue that entities in favor of continuing the CWIP Incentive gain financially from the incentive.³²⁴⁹ Industrial Customers state that the alleged benefits of the CWIP Incentive to customers are tenuous at best.³²⁵⁰

1530. Multiple commenters suggest that prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive may improve the planning and building of new transmission facilities.³²⁵¹ New England Systems, PJM States, and North Carolina Commission and Staff assert that removing the CWIP Incentive will appropriately reduce incentives to over-build transmission, which could lead to rates being unjust and unreasonable.³²⁵² Similarly, US Climate Alliance supports prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, as doing so would align incentives for transmission providers to deliver transmission projects on time and within budget.³²⁵³

1531. California Commission argues that money paid earlier as CWIP is more valuable than money paid later and that comparisons of savings under the CWIP Incentive and under AFUDC are only meaningful if an interest adjustment is

made to account for the time in which payments are made.³²⁵⁴ Industrial Customers explain that, to customers, the difference between the AFUDC and CWIP approaches is primarily the time value of money.³²⁵⁵ Kentucky Commission Chair Chandler, NASUCA, and California Commission express concern that today's ratepayers are forced to pay for tomorrow's transmission projects, which they refer to as intergenerational inequity, and they are especially concerned if a project will not provide service until a much later date.³²⁵⁶

2. Concerns With the NOPR Proposal

1532. Many commenters oppose the NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive.³²⁵⁷ Several commenters cite the Commission's findings in Order No. 679 explaining that the CWIP Incentive can help remove a disincentive to construct new transmission infrastructure, which can involve very long lead times and considerable risk to the utility that the project may not go forward.³²⁵⁸ National Grid and Avangrid, for example, argue that Long-Term Regional Transmission Facilities will likely have very long lead times and place even greater risk on transmission providers relative to transmission facilities planned and developed on a more typical timeframe.³²⁵⁹ Similarly, WIRES argues

that the rationale underlying the CWIP Incentive remains valid today.³²⁶⁰

1533. Some commenters also cite the Commission's 2012 Transmission Incentive Policy Statement as support for the CWIP Incentive as a risk-reducing mechanism to transmission providers, which these commenters state can increase credit ratings and lower capital costs.³²⁶¹ In addition, several commenters reference Commission findings in numerous prior incentive proceedings where the Commission has affirmed the benefits that the CWIP Incentive provides to customers and transmission providers, attesting that the NOPR proposal is in direct opposition to such findings.³²⁶²

1534. Some commenters assert that the NOPR proposal runs counter to obligations established in the Energy Policy Act of 2005 and FPA section 219 to facilitate capital investment in transmission infrastructure and would likely impede the development of regional transmission facilities identified to meet changes in the resource mix and demand.³²⁶³

1535. Numerous commenters argue that the proposal runs counter to the objectives of the NOPR that seek to encourage the development and completion of regional transmission facilities needed to address changes in

³²⁶⁰ WIRES Initial Comments at 17–18.

³²⁶¹ Ameren Initial Comments at 49; EEI Initial Comments at 42; Eversource Initial Comments at 32 (all citing *Promoting Transmission Investment Through Pricing Reform*, Policy Statement, 141 FERC ¶ 61,129, at P 12 (2012)).

³²⁶² AEP Initial Comments at 38 (citing *Ne. Utils. Serv. Co. & Nat'l Grid USA*, 125 FERC ¶ 61,183, at P 89 (2008)); Ameren Initial Comments at 49 (citing *United Illuminating*, 119 FERC ¶ 61,182, at P 63 (2007)); Duquesne Light Initial Comments at 3 (citing *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284, at P 58 (2007)); *Am. Elec. Power Service Corp.*, 116 FERC ¶ 61,059, at P 3 (2006)); EEI Initial Comments at 44 (citing *PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at PP 42–43 (2008), *reh'g denied*, 124 FERC ¶ 61,229 (2008)); National Grid Initial Comments at 29 (citing *Tucson Elec. Power Co.*, 174 FERC ¶ 61,223, at P 25 (2021)); *S. Cal. Edison Co.*, 172 FERC ¶ 61,241, at P 31 (2020); *United Illuminating Co.*, 167 FERC ¶ 61,126, at P 36 (2019)); MISO TOs Initial Comments at 66–67 (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,229, at P 78 (2011); *Duquesne Light Co.*, 166 FERC ¶ 61,074, at P 32 (2019); *United Illuminating Co.*, 167 FERC ¶ 61,126 at P 36; *GridLiance W. Transco LLC*, 164 FERC ¶ 61,049, at P 25 (2018); *NextEra Energy Transmission N.Y., Inc.*, 162 FERC ¶ 61,196, at P 64 (2018); *PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,089, at P 33 (2017); *Duquesne Light Co.*, 179 FERC ¶ 61,218, at P 17 (2022)); New York TOs Initial Comments at 23 (citing *Okla. Gas & Elec. Co.*, 133 FERC ¶ 61,274, at P 48 (2010); *Pepco Holdings, Inc.*, 125 FERC ¶ 61,130, at P 63 (2008)).

³²⁶³ Ameren Initial Comments at 48; CAISO Initial Comments at 43–44; EEI Initial Comments at 42–43; Indicated PJM TOs Initial Comments at 26–28; MISO TOs Initial Comments at 71–72; National Grid Initial Comments at 28; PPL Initial Comments at 29–30; WIRES Initial Comments at 17–18.

³²⁵⁴ California Commission Reply Comments at 13.

³²⁵⁵ Industrial Customers Reply Comments at 9.

³²⁵⁶ Kentucky Commission Chair Chandler Initial Comments at 8; NASUCA Initial Comments at 9; California Commission Reply Comments at 17 (citing NASUCA Initial Comments at 9).

³²⁵⁷ AEP Initial Comments at 38–40; Ameren Initial Comments at 48–51; Avangrid Initial Comments at 24–28; CAISO Initial Comments at 43–45; Consumer Organizations Initial Comments at 7–10; Duke Initial Comments at 44–45; Duquesne Light Initial Comments at 2–6; EEI Initial Comments at 42–45; EEI Reply Comments at 17–18; Entergy Initial Comments at 35–37; Eversource Initial Comments at 31–35; Eversource Reply Comments at 2; Harvard ELI Initial Comments at 7–10; Indicated PJM TOs Initial Comments at 26–28; MISO TOs Initial Comments at 65–66; National Grid Initial Comments at 27–30; New York TOs Initial Comments at 23–24; New York Transco Initial Comments at 13–16; Pattern Energy Initial Comments at 34–36; PG&E Initial Comments at 18–20; PPL Initial Comments at 29–30; SoCal Edison Initial Comments at 13–14; Transource Initial Comments at 3; WIRES Initial Comments at 17–19.

³²⁵⁸ Ameren Initial Comments at 49; EEI Initial Comments at 42–43; EEI Reply Comments at 17–18; Eversource Reply Comments at 2; MISO TOs Initial Comments at 66; National Grid Initial Comments at 28–29; WIRES Initial Comments at 17–18 (all citing Order No. 679, 116 FERC ¶ 61,057 at P 115).

³²⁵⁹ Avangrid Reply Comments at 6–7; National Grid Initial Comments at 28–29.

³²⁴⁶ Dominion Initial Comments at 53.

³²⁴⁷ Massachusetts Attorney General Initial Comments at 24–25; North Carolina Commission and Staff Initial Comments at 18; North Dakota Commission Initial Comments at 6; Pennsylvania Commission Initial Comments at 17–18; PJM States Initial Comments at 13; US Climate Alliance Initial Comments at 2.

³²⁴⁸ Massachusetts Attorney General Initial Comments at 24–25; North Dakota Commission Initial Comments at 6.

³²⁴⁹ New England Systems Reply Comments at 15–16 (citing Avangrid Initial Comments at 26).

³²⁵⁰ Industrial Customers Reply Comments at 9–10.

³²⁵¹ North Carolina Commission and Staff Initial Comments at 18; Pennsylvania Commission Initial Comments at 17; PJM States Initial Comments at 13; US Climate Alliance Initial Comments at 2.

³²⁵² New England Systems Reply Comments at 14–15; North Carolina Commission and Staff Initial Comments at 18; PJM States Initial Comments at 13.

³²⁵³ US Climate Alliance Initial Comments at 2.

the resource mix or demand over a longer time horizon.³²⁶⁴ For example, CAISO, MISO TOs, and Avangrid suggest that it is counterintuitive for the Commission to acknowledge a lack of regional transmission facilities in the NOPR, yet propose to undo the most reasonable tool that aids cash flow and reduces uncertainty associated with building those facilities.³²⁶⁵ Certain commenters state that the CWIP Incentive assists with getting needed transmission projects built.³²⁶⁶ AEP and Avangrid state that the CWIP Incentive is particularly well-suited to incentivizing the type of large, regional transmission projects that the Commission hopes to increase through the NOPR, which often present higher costs, longer lead times, an increase in possible rate shock, and present cash flow difficulties.³²⁶⁷

1536. Several commenters point to cash flow benefits enabled through the CWIP Incentive and associated benefits to customers.³²⁶⁸ For example, New York TOs and PG&E contend that the cash flow benefits from the CWIP Incentive allow a utility to reduce the need for external financing and instead allocate capital to other projects that benefit additional ratepayers.³²⁶⁹

1537. Several commenters contend that the Commission has failed to adequately justify the NOPR proposal, asserting that the rationale is weak or arguing that the Commission has not shown that its existing policy is unjust and unreasonable.³²⁷⁰ MISO TOs argue

that the Commission's claim that ratepayers do not receive benefits from the regional transmission facilities during the construction period is unsupported by precedent or analysis and is contrary to longstanding Commission policy. Further, they observe that a transmission facility cannot be developed and placed into service overnight, so artificially dividing up the customer benefits to pre-operation and post-operation ignores the realities of transmission development.³²⁷¹ Where the proposal identified that additional ratepayer protections may be necessary to balance customers' interest in just and reasonable rates against investors' interest in earning a return on invested capital or mitigating against over-investment in regional transmission facilities, MISO TOs reiterate that the CWIP Incentive's benefits promote just and reasonable rates by providing incentives encouraging transmission construction consistent with the Commission's FPA mandate and assert that an investor's rate of return is set in unrelated proceedings.³²⁷²

1538. Pattern Energy states that the Commission has provided no policy justification or factual basis to distinguish the risk incurred during the planning phase from other risk factors, such as size, scope, or cost, which it asserts is a departure from the Order No. 679 policy on the CWIP Incentive.³²⁷³

1539. Many commenters also argue that, while the NOPR proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive is intended to mitigate shifting too much risk to customers, the proposal ignores many of the benefits that the current CWIP Incentive policy providers to customers.³²⁷⁴ EEI argues that commenters that support the proposal also fail to recognize these benefits and

the important role that this incentive serves in facilitating new transmission investment.³²⁷⁵ Many commenters that oppose the NOPR proposal tout such benefits, such as improved cash flow and the ability for transmission providers to secure better financing through higher credit ratings, resulting in lower interest expense costs that benefit customers.³²⁷⁶ Consumer Organizations and Eversource contend that carrying a significant amount of debt in AFUDC rather than being recovered through the CWIP Incentive can result in lower credit ratings and higher capital costs, which are passed through to customers, and assert that "with AFUDC, consumers are likely to pay more in the long run."³²⁷⁷

1540. Some commenters state that the CWIP Incentive helps to avoid rate shock and provides other cost savings relative to AFUDC.³²⁷⁸ Avangrid states that arguments about the sharing of risk between utilities and customers that the Commission used to support the NOPR proposal fail to consider the budgeting risk to customers under the AFUDC approach, and claims that these arguments ignore the benefit of price stability.³²⁷⁹

1541. Several commenters state that the Commission can take more targeted action to address concerns of uncertainty in Long-Term Regional Transmission Planning rather than prohibiting Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive, for instance, by ensuring sufficiently robust selection criteria, project review, and

³²⁶⁴ AEP Initial Comments at 39; Ameren Initial Comments at 50–51; Avangrid Initial Comments at 25; Avangrid Reply Comments at 6–8; Eversource Initial Comments at 2, 31–32; MISO TOs Initial Comments at 70–76; Pattern Energy Initial Comments at 35–36; PG&E Initial Comments at 18–19.

³²⁶⁵ Avangrid Reply Comments at 7 (citing CAISO Initial Comments at 45; MISO TOs Initial Comments at 71–72, 74–75); CAISO Initial Comments at 45; MISO TOs Initial Comments at 74–76 (citing NOPR, 179 FERC ¶ 61,028 at PP 1, 9, 25, 35, 47, 330–331).

³²⁶⁶ AEP Initial Comments at 39; Ameren Initial Comments at 50; Avangrid Initial Comments at 26; MISO TOs Initial Comments at 69.

³²⁶⁷ AEP Initial Comments at 39; Avangrid Reply Comments at 10.

³²⁶⁸ AEP Initial Comments at 38–39; Ameren Initial Comments at 49; Avangrid Initial Comments at 25; EEI Initial Comments at 44–45; EEI Reply Comments at 17; Entergy Initial Comments at 37; Eversource Initial Comments at 31; Indicated PJM TOs Initial Comments at 26–28; MISO TOs Initial Comments at 66–67, 71, 74–76; National Grid Initial Comments at 28–29; New York TOs Initial Comments at 23–24; New York Transco Initial Comments at 13; Pattern Energy Initial Comments at 35; PG&E Initial Comments at 19; Transource Initial Comments at 3; WIRES Initial Comments at 17–18.

³²⁶⁹ New York TOs Initial Comments at 23–24; PG&E Initial Comments at 19.

³²⁷⁰ Ameren Initial Comments at 50–51; Duke Initial Comments at 44–45; Duquesne Light Initial

Comments at 2–3; EEI Initial Comments at 44–45; Eversource Initial Comments at 33–34; MISO TOs Initial Comments at 66–67 (citing NOPR, 179 FERC ¶ 61,028 at P 331); Pattern Energy Initial Comments at 35.

³²⁷¹ MISO TOs Initial Comments at 69 (citing NOPR, 179 FERC ¶ 61,028 at P 331).

³²⁷² *Id.* at 72–73 (citing NOPR, 179 FERC ¶ 61,028 at P 331).

³²⁷³ Pattern Energy Initial Comments at 35.

³²⁷⁴ AEP Initial Comments at 38–39; Ameren Initial Comments at 48–51; Avangrid Initial Comments at 27–28; Duke Initial Comments at 45; Duquesne Light Initial Comments at 3–5; EEI Initial Comments at 44–45; EEI Reply Comments at 18; Eversource Initial Comments at 31–34; Indicated PJM TOs Initial Comments at 26; MISO TOs Initial Comments at 66–76; National Grid Initial Comments at 29; New York TOs Initial Comments at 23–24; New York Transco Initial Comments at 13–14; PG&E Initial Comments at 19–20; SoCal Edison Initial Comments at 3, 13–14; WIRES Initial Comments at 18–19.

³²⁷⁵ EEI Reply Comments at 18 (citing NASUCA Initial Comments at 8–9; Transmission Dependent Utilities Initial Comments at 2–4).

³²⁷⁶ Ameren Initial Comments at 42, 50; Avangrid Initial Comments at 27; Duke Initial Comments at 45; Duquesne Light Initial Comments at 4–6; EEI Initial Comments at 44–45; MISO TOs Initial Comments at 66–67; PG&E Initial Comments at 19.

³²⁷⁷ Consumer Organizations Initial Comments at 7–8; Eversource Reply Comments at 4 (quoting Consumer Organizations Initial Comments at 7).

³²⁷⁸ AEP Initial Comments at 38–39; Ameren Initial Comments at 50; Avangrid Initial Comments at 27–28; Avangrid Reply Comments at 10 (citing Kentucky Commission Chair Chandler Initial Comments at 4–9); Consumer Organizations Initial Comments at 7–10; Duquesne Light Initial Comments at 4; EEI Initial Comments at 44; EEI Reply Comments at 17–18; Eversource Initial Comments at 31–32; Eversource Reply Comments at 4–5; Indicated PJM TOs Initial Comments at 26; MISO TOs Initial Comments at 66–76; National Grid Initial Comments at 28–29; New York TOs Initial Comments at 23–24; PG&E Initial Comments at 19; PG&E Reply Comments at 13–14; SoCal Edison Initial Comments at 13–14; WIRES Initial Comments at 19.

³²⁷⁹ Avangrid Reply Comments at 10 (citing Kentucky Commission Chair Chandler Initial Comments at 4–9).

approval processes.³²⁸⁰ CAISO contends that these measures are more appropriate ways to account for the root cause of the risk of over-building and to ensure that customers are protected from the costs of transmission facilities that may be less certain.³²⁸¹ R Street states that the NOPR's proposal to remove the CWIP Incentive by itself will not thwart increasing transmission costs, and the Commission must recognize preserving and expanding competition as a way to contain costs.³²⁸²

1542. Eversource and New York Transco assert that case-by-case evaluation for any request for transmission incentives, including the CWIP Incentive, affords interested parties the opportunity to intervene and provide comments, culminating in a Commission determination of whether the incentive is just and reasonable, thereby protecting customer interests.³²⁸³

1543. Eversource, Harvard ELI, and National Grid state that it would be best to make changes in incentives policy in a comprehensive transmission incentives rulemaking instead of in this final order.³²⁸⁴ Eversource and National Grid argue that, at a minimum, the Commission should defer a decision on the CWIP Incentive to the rulemaking proceeding on transmission incentives in Docket No. RM20–10–000, where the Commission has already established a full and complete record.³²⁸⁵ Harvard ELI suggests that any action on the CWIP Incentive be deferred to another proceeding to develop a holistic package of incentives, penalties, and oversight mechanisms after the Commission has established the full goals and procedural rules for Long-Term Regional Transmission Planning.³²⁸⁶

1544. Certain commenters raise concerns of unintended consequences of the proposal. CAISO and Transource state that new transmission developers may be disadvantaged if the Commission prohibits Long-Term Regional Transmission Facilities from being eligible for the CWIP

Incentive.³²⁸⁷ Specifically, CAISO notes that the Commission approved a provision in its OATT that permits a nonincumbent transmission developer within CAISO to recover Commission-authorized transmission revenue requirements associated with transmission projects under construction before the facilities are turned over to CAISO operational control, which CAISO contends is a way that it addresses barriers to transmission development by nonincumbent transmission developers.³²⁸⁸ CAISO contends that the Commission should not preclude transmission developers from using the CWIP Incentive for Long-Term Regional Transmission Facilities, especially because the Commission would continue to allow the CWIP Incentive for reliability and economic transmission projects.³²⁸⁹

3. Interaction of the CWIP Incentive With the Abandoned Plant Incentive

1545. Many commenters raise concerns with the interaction between the CWIP Incentive and the transmission incentive that allows applicants to request 100% of prudently-incurred costs associated with abandoned transmission projects be included in transmission rates if such abandonment is outside the control of management (Abandoned Plant Incentive).³²⁹⁰ APPA, California Commission, Industrial Customers, NARUC, and Virginia Attorney General suggest that unless and until the Commission reconsiders the Abandoned Plant Incentive, customers will continue to face risks associated with Long-Term Regional Transmission Facilities.³²⁹¹ Specifically, APPA states that the proposal to prohibit Long-Term Regional Transmission Facilities from being eligible for the CWIP Incentive will not necessarily protect customers from the costs of potentially unneeded facilities identified through Long-Term Regional Transmission Planning, given the Commission's policies on recovery of abandoned plant costs (including the Abandoned Plant Incentive under Order

No. 679).³²⁹² Similarly, NARUC, Virginia Attorney General, and Industrial Customers request that the Commission review the current abandoned plant policy to ensure that customer benefits from the adoption of the NOPR proposal with respect to the CWIP Incentive do not disappear if those costs are still recovered from customers as abandoned plant.³²⁹³

1546. Industrial Customers suggest that, without additional reforms limiting the recovery of abandoned plant costs, customers will continue to face the possibility of paying for transmission that is never built.³²⁹⁴ Further, Industrial Customers and California Commission state that AFUDC could be a superior approach for customers, but only in a final order that adopts certain protections to ensure that customers do not pay for abandoned plant costs.³²⁹⁵ Industrial Customers argue that the Commission should adopt customer safeguards for transmission projects that are abandoned, including a more thorough review of whether costs were prudently incurred prior to abandonment.³²⁹⁶

C. Commission Determination

1547. We decline to act at this time to finalize the NOPR proposal to limit the availability of the CWIP Incentive for Long-Term Regional Transmission Facilities. We agree with commenters³²⁹⁷ that any action on the CWIP Incentive is more appropriately considered in a separate proceeding to allow for a holistic approach to transmission incentives after the Commission has finalized its Long-Term Regional Transmission Planning reforms. In particular, we conclude that whether the Commission's transmission incentives are appropriately "benefitting consumers by ensuring reliability and reducing the cost of delivered power"³²⁹⁸ is a question better evaluated by considering the Commission's transmission incentives comprehensively for all regional transmission facilities.

³²⁹² APPA Initial Comments at 46–47.

³²⁹³ Industrial Customers Reply Comments at 10 (citing MISO States Initial Comments at 14; NARUC Initial Comments at 55); NARUC Initial Comments at 55; Virginia Attorney General Reply Comments at 5 (citing NARUC Initial Comments at 55).

³²⁹⁴ Industrial Customers Initial Comments at 25–26.

³²⁹⁵ California Commission Reply Comments at 19 (citing Industrial Customers Initial Comments at 27); Industrial Customers Initial Comments at 26–27.

³²⁹⁶ Industrial Customers Reply Comments at 9.

³²⁹⁷ Eversource Initial Comments at 33; Harvard ELI Initial Comments at 4–5, 7–8, 10; National Grid Initial Comments at 27.

³²⁹⁸ 16 U.S.C. 824s(a).

³²⁸⁰ Avangrid Reply Comments at 8 (citing CAISO Initial Comments at 45); CAISO Initial Comments at 45; EEI Reply Comments at 18; PG&E Reply Comments at 13–14.

³²⁸¹ CAISO Initial Comments at 6–7, 45.

³²⁸² R Street Reply Comments at 2.

³²⁸³ Eversource Reply Comments at 4–5; New York Transco Reply Comments at 7–8.

³²⁸⁴ Eversource Initial Comments at 33; Harvard ELI Initial Comments at 4–5, 7–8, 10; National Grid Initial Comments at 27.

³²⁸⁵ Eversource Initial Comments at 33; National Grid Initial Comments at 27.

³²⁸⁶ Harvard ELI Initial Comments at 4–5, 7–8, 10.

³²⁸⁷ CAISO Initial Comments at 43–45;

Transource Initial Comments at 3.

³²⁸⁸ CAISO Initial Comments at 43–44 (citing *Cal. Indep. Sys. Operator Corp.*, 146 FERC ¶ 61,237 (2014)).

³²⁸⁹ *Id.* at 44–45.

³²⁹⁰ Order No. 679, 116 FERC ¶ 61,057 at P 163.

³²⁹¹ APPA Initial Comments at 46–47; California Commission Reply Comments at 19 (citing Industrial Customers Initial Comments at 27); Industrial Customers Initial Comments at 24–27; Industrial Customers Reply Comments at 9; NARUC Initial Comments at 55; Virginia Attorney General Initial Comments at 6–7; Virginia Attorney General Reply Comments at 5–6.

VIII. Exercise of a Federal Right of First Refusal in Commission-Jurisdictional Tariffs and Agreements

A. NOPR Proposal

1548. In the NOPR, the Commission proposed to use the discretion afforded by FPA section 309 to amend Order No. 1000's findings and nonincumbent transmission developer reforms in part, so as to permit the exercise of Federal rights of first refusal for selected transmission facilities, conditioned on the incumbent transmission provider with the Federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain proposed requirements described in the NOPR.³²⁹⁹ The Commission reasoned that given the investment trends observed since Order No. 1000's implementation, it is possible that the Commission's Order No. 1000 nonincumbent transmission developer reforms may be inadvertently discouraging investment in and development of regional transmission facilities to some extent.³³⁰⁰ Specifically, the Commission posited that incumbent transmission providers, as a result of those reforms, may be presented with perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint.³³⁰¹

1549. The Commission preliminarily found that, while the *unconditional* exercise of Federal rights of first refusal for entirely new selected transmission facilities remains unjust and unreasonable, Order No. 1000's remedy—requiring the elimination of *all* Federal rights of first refusal for entirely new selected transmission facilities—was overly broad.³³⁰² The Commission further preliminarily found that, while Order No. 1000's reforms have a sound theoretical basis, the remedy prescribed by Order No. 1000 failed to recognize that some of the expected benefits from the competitive transmission development processes could be achieved or at least reasonably approximated through other means.³³⁰³

1550. Accordingly, the Commission proposed to allow transmission providers to propose, pursuant to FPA section 205, new Federal rights of first

refusal for incumbent transmission providers, conditioned on the incumbent transmission provider with the Federal right of first refusal for such regional transmission facilities establishing joint ownership of the transmission facilities consistent with certain requirements described in the NOPR.³³⁰⁴ The Commission asserted that if the NOPR proposal was adopted, Order No. 1000's findings and mandates would be amended such that joint ownership conditions would presumptively be found to ensure just and reasonable Commission-jurisdictional rates and limit opportunities for undue discrimination by transmission providers, if imposed upon the exercise of an incumbent transmission provider's Federal right of first refusal for selected transmission facilities.

1551. The Commission explained that an incumbent transmission provider could establish qualifying joint ownership with unaffiliated nonincumbent transmission developers as defined in Order No. 1000, or another unaffiliated entity, including another incumbent transmission provider.³³⁰⁵ However, the Commission also proposed that to qualify for the presumption, incumbent transmission providers with a conditional Federal right of first refusal would not be allowed to structure joint-ownership arrangements such that unaffiliated entities were offered less than a meaningful level of participation and investment in the proposed regional transmission facility.³³⁰⁶ The Commission further explained that an incumbent transmission provider's conditional Federal right of first refusal should not significantly delay the regional transmission planning process or result in prolonged uncertainty regarding which transmission facilities will (or, alternatively, will not) be subject to competitive transmission development processes.³³⁰⁷

1552. The Commission noted that proposals for jointly owned regional transmission facilities would still need to be evaluated by transmission providers in the transmission planning region and would not be exempt from selection requirements. However, the Commission also explained that the evaluation process for such jointly owned regional transmission facility proposals would not involve running

the region's competitive transmission development process.³³⁰⁸

B. Comments

1. General Perspectives and Approach To Reform

1553. Commenters share a variety of perspectives on the track record of competitive transmission development processes, the wisdom of the nonincumbent transmission developer reforms adopted in Order No. 1000, and the steps they believe the Commission should take in response to the concerns identified in the NOPR. Several state entities, customer-affiliated groups, and nonincumbent transmission developers, such as LS Power, NextEra, and the US DOJ and FTC, defend competitive transmission development processes as beneficial and argue for their expansion.³³⁰⁹ Some US Senators agree, arguing that allowing for a conditional Federal right of first refusal would be anti-competitive, could hinder development of new transmission, and could cause excessive costs to consumers.³³¹⁰ On the other hand, representatives of incumbent transmission providers and others (*e.g.*, EEI, WIRES, DATA, the MISO TOs) critique such processes and many call for the Commission to restore unconditional Federal rights of first refusal.³³¹¹ Each side of the debate

³³⁰⁸ *Id.* P 370.

³³⁰⁹ See, *e.g.*, American Municipal Power Reply Comments at 3–4; Anbaric Initial Comments at 4–5; California Commission Initial Comments at 100, 103–104; Competition Advocates Supplemental Comments at 1–3 & n.17 (citing Jennifer Chen & Devin Hartman, R Street Institute, *Transmission Reform Strategy from a Customer Perspective: Optimizing Net Benefits and Procedural Vehicles* (May 2022), <http://www.rstreet.org/research/transmission-reform-strategy-from-a-customer-perspective-optimizing-net-benefits-and-procedural-vehicles>); Competition Coalition Initial Comments at 16–22, 68–70; LS Power Initial Comments at 38–39, 44; LS Power Partial Reply Comments at 20–23; LS Power and NRG Supplemental Comments at 38–39; NextEra Initial Comments at 18–19, 24–27, 29; Ohio Consumers Reply Comments at 16–18; Resale Iowa Reply Comments at 5–6; US DOJ and FTC Initial Comments at 7–8, 10–11, 13, 22.

³³¹⁰ U.S. Senators Heinrich and Lee Supplemental Comments at 1–2. See also Freeport-McMoRan Supplemental Comments at 6 (asserting that the Federal right of first refusal is anticompetitive and would enrich transmission owning utility shareholders).

³³¹¹ See, *e.g.*, DATA Initial Comments at 3–7 (detailing experiences by transmission planning regions and concluding that “competitive processes have become a distraction from, and an impediment to, the larger goal of expanding the transmission system to support current and future needs”); EEI Initial Comments at 24, 26, 27–31; EEI Supplemental Comments at 1–3 (citing Concentric Energy Advisors, *Competitive Transmission: Experience To-Date Shows Order No. 1000 Solicitations Fail to Show Benefits*, at 1 (Aug. 2022) (2022 Concentric Report); DATA Supplemental

³²⁹⁹ See NOPR, 179 FERC ¶ 61,028 at P 351.

³³⁰⁰ *Id.* P 350.

³³⁰¹ *Id.*

³³⁰² *Id.* PP 351–352, 354.

³³⁰³ *Id.* P 353.

³³⁰⁴ *Id.* P 354.

³³⁰⁵ *Id.* P 365.

³³⁰⁶ *Id.* P 371.

³³⁰⁷ *Id.* P 366.

offers consultant reports to substantiate their position, with pro-competition advocates relying on studies by the Brattle Group (Brattle) that present competitive transmission development processes in a largely favorable light,³³¹² and advocates for Federal rights of first refusal relying on contrasting studies by Concentric Energy Advisors (Concentric).³³¹³ In general, pro-competition advocates, such as LS Power, contend that competitive transmission development processes are essential to just and reasonable rates, while representatives of incumbent transmission providers counter that just and reasonable transmission rates are separately and independently ensured by and through FPA section 205 rate proceedings.³³¹⁴

Comments at 4); MISO TOs Initial Comments at 53–56; National Grid Initial Comments at 4–5, 31 (doubting that Order No. 1000 competitive transmission development processes have broadly produced beneficial outcomes); PJM Initial Comments at 47–48 (enumerating the challenges faced in and resources required to complete competitive transmission development processes); Vermont Electric and Vermont Transco Initial Comments at 4–5 (referencing “a number of unintended consequences that have not benefited the regional grid”); WIRES Initial Comments at 14–15; WIRES Reply Comments at 4–8; Xcel Initial Comments at 5 (“[Right of first refusal] elimination was a policy experiment that did not bring about the desired result.”).

³³¹² In general, Brattle’s analysis has found that competitive transmission development processes have yielded “cost savings averaging between 20% and 30%” once historical levels of cost escalation in transmission development were taken into account. See Brattle Apr. 2019 Competition Report at 39–43. US DOJ and FTC also contend that there are many instances in which competitive transmission development processes have benefitted consumers. See US DOJ & FTC Initial Comments at 13–16 (collecting examples); but see DATA Initial Comments at 7–9 (critiquing Brattle’s analyses); WIRES Reply Comments at 5 (same).

³³¹³ In addition to citations to past Concentric reports, DATA attaches to its initial comments a 2022 Concentric report, which DATA characterizes as showing that competitive transmission development processes add significant time, delay customer benefits, and do not produce clear evidence of customer savings given cost cap exclusions and delays. DATA Initial Comments at 1–2, 7–11, 14–15; *id.* at attach. A (2022 Concentric Report). DATA also attaches to its comments a whitepaper that DATA alleges updates the Brattle Apr. 2019 Competition Report, and which DATA contends shows that Order No. 1000-mandated competition resulted in exceeding cost baselines by at least six percent. DATA Supplemental Comments at 3–4; *id.* at attach.: Whitepaper (DATA, *Revisiting the Evidence on Cost Savings from Transmission Competition* (Dec. 2023) (2023 DATA Whitepaper)). But see Massachusetts Attorney General Reply Comments at 8–9 (critiquing the 2022 Concentric Report); NextEra Reply Comments at 3, 7–17 (same); see also Competition Coalition Supplemental Comments at 2–7 (arguing that, in addition to DATA lacking good cause and failing to file a motion to lodge new evidence, the 2023 DATA Whitepaper fails to, among other things, demonstrate that cost-of-service regulation is as effective as competition in establishing just and reasonable transmission rates).

³³¹⁴ Compare LS Power Initial Comments at 32–37, with Ameren Initial Comments at 36–37, and

1554. At a high level, pro-competition commenters express concern that the NOPR proposal could divert regional transmission facility development opportunities to incumbent transmission providers, opportunities that would otherwise be subject to competitive transmission development processes. For example, US DOJ and FTC argue that relying on Federal rights of first refusal to address the problems the Commission has identified would eliminate or distort the benefits of competitive transmission development processes, which generally “make transmission development less costly, more resilient, and more innovative.”³³¹⁵ NESCOE “implores the Commission to maintain flexibility that enables ISO–NE to issue competitive solicitations to identify projects in furtherance of state laws.”³³¹⁶ Some pro-competition commenters believe that states and state commissions are best positioned to determine whether competition between nonincumbent transmission developers and incumbent transmission providers is beneficial.³³¹⁷

1555. Meanwhile, commenters that generally support Federal rights of first refusal express skepticism that the NOPR proposal would be sufficient to address the identified problems, or offer only qualified support for the NOPR proposal as an inferior alternative to the Commission fully restoring unconditional Federal rights of first refusal.³³¹⁸ In addition, if adopted, several incumbent transmission providers advocate for requiring transmission providers to implement the NOPR proposal instead of

permitting them to decide whether to implement it.³³¹⁹

1556. While commenters offer numerous variations on these high-level opposing views, several commenters argue that there are problems with the basic structure of competitive transmission development processes and express concerns that generally align with those expressed by the Commission in the NOPR. For example, while not agreeing with the NOPR proposal, ELCON expresses concern that “current competition regimes have led eligible developers to retreat to their various corners, which reduces transparency, information sharing, and open dialogue in the planning process[.]” and contends that both incumbent transmission owners and nonincumbent transmission developers have adopted a zero-sum posture to transmission planning that leads to a patchwork of planning and lack of innovation.³³²⁰ Similarly, WIRES, citing a report by Grid Strategies, suggests that reforms under Order No. 1000 often prevent information sharing about transmission needs and available solutions, and lead to less cooperation and coordination within transmission planning regions.³³²¹ Harvard ELI disagrees, however, arguing that the report cited by WIRES provides evidence that information asymmetry, secrecy, and utilities’ incentives demonstrate undue discrimination.³³²²

1557. Though it does not support the NOPR proposal, Cypress Creek contends that Order No. 1000 led to misaligned incentives such that “competition today has not necessarily fostered just and

DATA Initial Comments at 13–14, and MISO TOs Initial Comments at 60–61. Several commenters argue at length about the NOPR proposal’s invocation of FPA sections 309 and 206 as legal authority and explore various alternatives. See, e.g., Ameren Initial Comments at 38–39; California Commission Initial Comments at 101–103; DATA Initial Comments at 17–18 & n.43; Eversource Initial Comments at 39–42; Indicated PJM TOs Initial Comments at 34–35; ITC Initial Comments at 36; LS Power Initial Comments at 14, 19–20, 24, 57–61; MISO TOs Initial Comments at 50–53; NextEra Initial Comments at 51–53.

³³¹⁵ See US DOJ & FTC Initial Comments at 22.

³³¹⁶ NESCOE Supplemental Comments at 6–7.

³³¹⁷ E.g., California Commission Initial Comments at 104–105; Harvard ELI Initial Comments at 5–6, 31–33; see also Minnesota State Entities Initial Comments at 9; Mississippi Commission Reply Comments at 8 & n.31; New Jersey Commission Initial Comments at 37; PIOs Initial Comments at 85; PJM States Initial Comments at 13–14. But see NextEra Reply Comments at 23–25 (questioning whether allowing states to dictate the terms of a filed rate would be legally sound); PJM Reply Comments at 25–29 (raising potential legal ambiguities and practical issues).

³³¹⁸ E.g., Avangrid Initial Comments at 18–24; DATA Initial Comments at 20–22; Eversource Initial Comments at 35–36, 42–45; Indicated PJM TOs Reply Comments at 2, 13–14; ITC Initial Comments at 32–43; Xcel Initial Comments at 5.

³³¹⁹ See, e.g., DATA Initial Comments at 19–21; Exelon Initial Comments at 49–51; National Grid Initial Comments at 36–37; PG&E Initial Comments at 2, 11; PPL Initial Comments at 34; SoCal Edison Initial Comments at 2; WIRES Initial Comments at 16; see also LS Power Initial Comments at 74–76 (discussing FPA section 205 rights in various regions); PJM Initial Comments at 30 (questioning whether there are any “regional differences” on this policy issue). But see Idaho Power Initial Comments at 12 (urging the Commission to ensure that any proposed reforms provide sufficient flexibility to tailor transmission planning and cost allocation processes to accommodate unique regional characteristics).

³³²⁰ ELCON Initial Comments at 21–22; see also DATA Reply Comments at 14 (arguing that “the Order No. 1000 status quo creates an inexorable drive towards minimalist, short-term solutions”). Despite its opposition to the NOPR proposal, ELCON sees some potential benefit of encouraging joint ownership and cooperation-based approaches, which ELCON thinks may help remedy the “‘us versus them’ problems with the current regional planning process.” ELCON Initial Comments at 23–24.

³³²¹ WIRES Supplemental Comments at 4 (citing Rob Gramlich, Richard Doying, & Zach Zimmerman, Grid Strategies, *Fostering Collaboration Would Help Build Needed Transmission* (Feb. 2024)).

³³²² Harvard ELI Supplemental Comments at 5.

reasonable rates.”³³²³ Similarly, American Municipal Power states that many municipal electric systems are located on the fringe of an incumbent transmission provider’s system and would significantly benefit from regional transmission projects that improve reliability, although because such projects require coordination between two incumbent transmission providers, they are “largely ignored.”³³²⁴ American Municipal Power also states that another disincentive to incumbent transmission provider regional transmission facility development is the possibility of losing the project to another developer through the competitive process.³³²⁵ While not taking a position on competitive transmission development processes, Indiana Commission agrees that Order No. 1000 has produced unintended consequences, including that transmission development now mostly takes the form of transmission facilities not subject to competitive transmission development processes,³³²⁶ and states that little region-wide economic transmission development is occurring.³³²⁷

1558. But some commenters, such as NextEra, contend that if regional transmission investment has lagged behind expectations under Order No. 1000, that is a planning issue, not an incentives issue, and that some of the NOPR’s proposed transmission planning reforms will help lead to greater investment in regional transmission facilities.³³²⁸ LS Power argues that the NOPR only generally observed that

there have been increases in local transmission facility investment and static or declining investment in regional transmission facilities, and did not specify particular transmission planning regions in which this problem is occurring or which incumbent transmission providers face perverse investment incentives.³³²⁹ However, other commenters, such as WIRES, contend that the elimination of Federal rights of first refusal may be connected to flat or declining regional transmission investment,³³³⁰ as suggested by the NOPR.

1559. Finally, several commenters argue that the Commission should not adopt Federal right of first refusal reforms in this docket, but rather explore those and related issues in another forum. Advanced Energy United, Advanced Energy Buyers, State Agencies, and California Commission, for example, urge the Commission to consider these issues either in a different proceeding or at a technical conference.³³³¹ Competition Advocates support alternative reforms that they argue can better address the problem of perverse incentives, including better enforcement of existing orders or taking action to reduce Order No. 1000 exemptions, and establishing an independent transmission monitor.³³³²

2. Comments on the NOPR’s Joint Ownership Proposal

1560. Some commenters, including TAPS, highlight various ways in which the Commission’s joint ownership proposal would alleviate challenges associated with current regional transmission planning processes.³³³³ Some commenters, such as ELCON and

the Omaha Public Power District, argue that the Commission’s joint ownership proposal would benefit customers or encourage incumbent transmission providers to pursue larger and more comprehensive transmission solutions to the benefit of customers, and create incentives for transmission providers to find beneficial opportunities and investments for joint ownership partners and customers.³³³⁴ Other commenters agree that adopting the NOPR proposal may incentivize incumbent transmission providers to “look beyond the provincial” needs and consider regional and interregional solutions to transmission needs.³³³⁵

1561. However, numerous commenters criticize the NOPR proposal and its approach to joint ownership partner selection, especially its inclusion of another incumbent transmission provider as a potential joint ownership partner.³³³⁶ In general, these commenters contend that incumbent transmission providers would be free to only team up with fellow incumbent transmission providers with the same interests and exclude others, leading to results that would be contrary to the goals of Order No. 1000. As Anbaric states, two incumbent transmission providers (or their affiliates) could “team up and swap a portion of their respective projects as a means to satisfy the joint ownership requirement” and thereby “maintain the status quo”³³³⁷ rather

³³³⁴ See ELCON Initial Comments at 23–24; see also Cross Sector Representatives Supplemental Comments at 1 (arguing that the provisions are appropriately tied to collaborative and holistic planning outcomes that provide clear benefits to customers and would benefit the goals enunciated by the Commission throughout this rulemaking process); Omaha Public Power Initial Comments at 5 (suggesting that the joint ownership proposal will likely encourage neighboring incumbent transmission providers to develop facilities that benefit multiple transmission providers under certain conditions); Pattern Energy Initial Comments at 37 (asserting that joint ownership arrangements will open the market to additional investment opportunities for all parties).

³³³⁵ Tabors Caramanis Rudkevich Initial Comments at 2; see also Citizens Energy Initial Comments at 9–10; PG&E Initial Comments at 11 (arguing that a conditional Federal right of first refusal will help mitigate development challenges by promoting collaboration between partners).

³³³⁶ E.g., Anbaric Initial Comments at 18; see also, e.g., APPA Initial Comments at 11–12; California Commission Initial Comments at 80–88; Competition Coalition Initial Comments at 49–50; LS Power Initial Comments at 92–94; Massachusetts Attorney General Initial Comments at 48–49; New Jersey Commission Initial Comments at 31–33; NextEra Initial Comments at 49–51; NRECA Initial Comments at 58, 61; PJM States Initial Comments at 14; Policy Integrity Initial Comments at 21–22; TANC Initial Comments at 13; TAPS Initial Comments at 48–51; TAPS Reply Comments at 5–6 & n.25.

³³³⁷ Anbaric Initial Comments at 18.

³³²³ Cypress Creek Reply Comments at 16.

³³²⁴ American Municipal Power Initial Comments at 31–32.

³³²⁵ *Id.* at 32. However, American Municipal Power states that because regional transmission facilities typically traverse more than one incumbent transmission provider’s service territory, allowing individual incumbent transmission providers to exercise a Federal right of first refusal without other reforms also designed to promote coordination and cooperation between such providers would not “result in a shift from local to regional projects.” *Id.* (referencing the “interzonal nature of regional projects”).

³³²⁶ Indiana Commission Initial Comments at 12 (referring to “‘immediate need reliability’ or ‘end of life replacement’ or ‘supplemental’ or ‘other’” types of transmission facility projects).

³³²⁷ *Id.*

³³²⁸ See NextEra Initial Comments at 18–19, 25; see also *id.* at 43 (arguing that the NOPR proposal is insufficiently based on speculation about potentially flawed investment incentives); Americans for Fair Energy Prices Reply Comments at 5–6; Northwest and Intermountain Initial Comments at 19–20 (arguing that even a limited or conditional right of first refusal eliminates any incentive for the incumbent transmission provider to reduce costs or delays); Ohio Commission Federal Advocate Initial Comments at 18 (arguing that adopting the NOPR proposal would further misalign incentives for incumbent transmission providers, not improve them).

³³²⁹ LS Power Initial Comments at 73–74. *But see* PJM Initial Comments at 30 (questioning whether there are any “regional differences” on this policy issue).

³³³⁰ WIRES Reply Comments at 2 (citing WIRES Initial Comments at 13–14).

³³³¹ Advanced Energy Buyers Initial Comments at 4 n.6; AEE Initial Comments at 4, 35–37; AEE Reply Comments at 31–33; California Commission Initial Comments at 103–104; State Agencies Initial Comments at 11; State Agencies Reply Comments at 6; see also Chemistry Council Initial Comments at 8; Enel Initial Comments at 3; Harvard ELI Initial Comments at 7–10; NESCOE Initial Comments at 11, 74–77.

³³³² Competition Advocates Supplemental Comments at 3–4.

³³³³ See TAPS Initial Comments at 29–30 (stating that joint ownership arrangements provide benefits such as “improving transmission planning to produce a more efficient build-out; facilitating state siting; making it easier for [load-serving entities] to accept cost increases associated with new transmission by providing a hedge; and reducing the costs of needed facilities”), *id.* at 34–37; see also Eversource Initial Comments at 36–39; Pattern Energy Initial Comments at 37; PPL Initial Comments at 32–33; Vermont Electric and Vermont Transco Initial Comments at 4.

than advance innovation, cost savings, or new entry. NextEra and others decry this potential outcome, which could keep nonincumbent transmission developers from obtaining investment opportunities.³³³⁸ Relatedly, several commenters argue that the NOPR proposal would raise antitrust and competition concerns,³³³⁹ including US DOJ and FTC, which argue that because the joint venture will not be facing pressure to compete, the conditional Federal right of first refusal does not create the incentive for incumbent transmission providers to seek out the best partner.³³⁴⁰ In other words, US DOJ and FTC argue, the mere existence of a joint venture partner does not bring competition to a project, nor does it necessarily result in the best partner for a project being selected, in terms of skill, cost, or innovation.³³⁴¹

1562. Commenters also highlight the potential for uncertainty, litigation, and delays in attempting to implement the NOPR proposal. Anbaric asserts that a conditional Federal right of first refusal could add delays due to litigation over whether incumbent transmission providers provided meaningful opportunities to third parties.³³⁴² EEI cautions against putting transmission providers in a position where they must adjudicate what constitutes meaningful ownership of jointly owned transmission facilities on a case-by-case basis, recommending instead that the Commission provide guidance on the types of ownership rights or operational obligations that will qualify and establish a process for seeking Commission approval in a timely

manner for other arrangements.³³⁴³ MISO asserts that the process envisioned by the NOPR would be time-consuming, as would developing a joint ownership proposal, and asks that the Commission adopt clearly defined criteria for joint ownership, such as a *pro forma* agreement, in order not to impede transmission development.³³⁴⁴ National Grid calls for planning authorities to be given the authority to determine the appropriate criteria and conditions that constitute a valid joint ownership arrangement, though it also asks for guidance regarding particular types of combinations of potential joint owners.³³⁴⁵

C. Commission Determination

1563. We decline to act at this time to finalize the NOPR proposal. Rather, we will continue to consider the NOPR proposal and potential Federal right of first refusal issues in other proceedings. We do not adopt in this final order any changes to Order No. 1000's nonincumbent transmission developer reforms.

1564. As summarized above, commenters raise substantial concerns about whether incumbent transmission providers, as a result of Order No. 1000's reforms, face perverse investment incentives that do not adequately encourage those incumbent transmission providers to develop and advocate for transmission facilities that benefit more than just their own local retail distribution service territory or footprint. To the extent that incumbent transmission providers face perverse investment incentives, commenters also raise substantial concerns about whether the NOPR proposal adequately and appropriately addresses those incentives and whether adopting the proposal is necessary or appropriate in carrying out the provisions of the FPA. Therefore, after careful consideration of the record, we decline to finalize the NOPR proposal at this time. The Commission will continue to consider potential Federal right of first refusal

reforms along with other transmission reforms in the future.³³⁴⁶

IX. Local Transmission Planning Inputs in the Regional Transmission Planning Process

A. Need for Reform

1. NOPR

1565. In the NOPR, the Commission explained that it was concerned that local transmission planning processes may lack adequate provisions for transparency and meaningful input from stakeholders, and that regional transmission planning processes may not adequately coordinate with local transmission planning processes.³³⁴⁷ The Commission stated in the NOPR that it was concerned that the lack of minimal standards or specified procedures may contribute to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes.³³⁴⁸ Accordingly, the Commission stated that it believed reforms to better ensure transparency and opportunities for stakeholder engagement may be timely and important in light of the significant investments in transmission that now occur through local transmission planning processes.³³⁴⁹

1566. In addition, the Commission explained in the NOPR that it was concerned that, given the age of the Nation's transmission infrastructure, many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life without evaluating whether those replacement transmission facilities could be modified (*i.e.*, right-sized) to more efficiently or cost-effectively address regional transmission needs, and, more generally, that transmission providers developing regional transmission plans may lack the information necessary to identify the benefits that regional transmission facilities may provide in deferring or eliminating the need for in-kind replacements. Specifically, the NOPR stated that in-kind replacements

³³³⁸ See Harvard ELI Initial Comments at 35; NextEra Initial Comments at 49–51. In contrast, some commenters such as APPA urge the Commission to adopt a requirement that incumbent transmission providers offer joint ownership on reasonable terms at a load ratio share level to all unaffiliated load-serving entities in the incumbent transmission provider's footprint. See APPA Reply Comments at 5–6; TAPS Initial Comments at 30–32 (advocating for a similar proposal).

³³³⁹ See, e.g., Competition Coalition Initial Comments at 59–62; LS Power Initial Comments at 122–125, 131–134; US DOJ & FTC Initial Comments at 17–18.

³³⁴⁰ US DOJ & FTC Initial Comments at 17.

³³⁴¹ *Id.* at 17–18; see also LS Power Initial Comments at 93 (arguing that the NOPR proposal would not require any independent check that the incumbent transmission provider is partnering with the entity that offers the most benefits).

³³⁴² Anbaric Initial Comments at 16; see also Avangrid Initial Comments at 18 (noting that establishing a conditional Federal right of first refusal adds a layer of complexity to the development of transmission); NYISO Initial Comments at 55–56 (asking the Commission to consider the complications, disputes, and delays that may arise from attempting to implement a conditional Federal right of first refusal and other practical issues).

³³⁴³ EEI Initial Comments at 36–37; see also Ameren Initial Comments at 44; DATA Initial Comments at 21–22; PJM Initial Comments at 4–5, 51–52, 53–54.

³³⁴⁴ MISO Initial Comments at 80–83; see also APPA Initial Comments at 4–7, 20–22 (outlining a detailed proposed implementation process by which APPA believes incumbent transmission providers and load-serving entities could work together and help avoid disputes and delay); Invenenergy Reply Comments at 7–8 (calling for the adoption of *pro forma* agreements to ease implementation); TAPS Initial Comments at 53–54 (expressing concern that the NOPR proposal's anticipated period for formulation of joint ownership agreements is too short).

³³⁴⁵ See National Grid Initial Comments at 37.

³³⁴⁶ We note, for example, the ongoing proceeding in Docket No. AD22–8 on Transmission Planning and Cost Management.

³³⁴⁷ NOPR, 179 FERC ¶ 61,028 at P 398 & n. 639 (providing that regional transmission planning processes should identify “alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual utility transmission providers in their local transmission planning process” (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 148)).

³³⁴⁸ *Id.*

³³⁴⁹ See *supra* The Overall Need for Reform section.

of existing transmission facilities are managed by individual incumbent transmission providers according to their company practices, and that there is no requirement that transmission providers plan these in-kind replacement transmission facilities through an Order No. 890-compliant transmission planning process.³³⁵⁰ The Commission stated that, because in-kind replacement of existing transmission facilities is not subject to any transmission planning process, it was concerned that, absent reform, there may be a lack of coordination between regional transmission planning processes and in-kind replacement of existing transmission facilities to identify whether these replacement transmission facilities could be modified to more efficiently or cost-effectively address transmission needs identified through Long-Term Regional Transmission Planning. The Commission explained that this lack of coordination may result in a regional transmission planning process that fails to identify opportunities to right size planned in-kind replacement transmission facilities and may result in the development of duplicative or unnecessary transmission facilities that increase costs to customers and render Commission-jurisdictional rates unjust and unreasonable.³³⁵¹

2. Comments

1567. Some commenters argue that the NOPR proposal regarding improved transparency in local transmission planning processes is not justified.³³⁵² EEI argues that the Commission has not found that any of the approved transmission planning processes under Order Nos. 890 and 1000 are unjust and unreasonable or unduly discriminatory or preferential and that, absent such a finding, the Commission should not move forward with changes to local transmission planning processes.³³⁵³ Idaho Power states that the Commission should not use a general rulemaking to address localized problems.³³⁵⁴ On the other hand, Indicated PJM TOs state that the NOPR proposal to enhance

transparency in the local transmission planning processes is needed in each transmission planning region to satisfy the requirements set forth by Order No. 890.³³⁵⁵

1568. With respect to the Commission's proposed right-sizing reforms, LS Power and NextEra argue that the NOPR fails to make findings required under FPA section 206 to permit a right of first refusal for right-sized projects. LS Power and NextEra assert that the NOPR does not satisfy the first prong of FPA section 206, as it fails to make an affirmative finding that either the regional transmission planning process or the local transmission planning process are unjust and unreasonable such that abandonment of the existing tariff provisions is warranted.³³⁵⁶ Competition Coalition also asserts that the Commission failed to demonstrate the alleged need for reform on any section 206 finding.³³⁵⁷

3. Commission Determination

1569. Based on the record, we find that there is substantial evidence to support the conclusion that existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are unjust, unreasonable, and unduly discriminatory or preferential. We therefore adopt the preliminary findings in the NOPR concerning the need for reform of the local transmission planning process and coordination between the local and regional transmission planning processes, including the evaluation of whether replacement transmission facilities could be modified (*i.e.*, right-sized) to more efficiently or cost-effectively address transmission needs.³³⁵⁸

1570. Local and regional transmission planning processes serve essential and complementary roles in ensuring that

customers' transmission needs are identified and met at a just and reasonable cost, including through the identification, evaluation, and selection of more efficient or cost-effective transmission solutions through regional transmission planning. Information and transmission solutions developed through local transmission planning serve as a foundation for regional transmission planning, and it is therefore critical that the processes are appropriately designed and aligned to ensure that transmission providers and stakeholders have the information needed, including from the local transmission planning process, to conduct effective regional transmission planning. While the broader reforms directed in this final order are focused on improving the regional transmission planning process, we nonetheless have identified discrete deficiencies in the local transmission planning process and its coordination with the regional transmission planning process that also must be addressed to ensure that Commission-jurisdictional rates are just and reasonable.

1571. First, we find that local transmission planning processes lack adequate provisions for transparency and meaningful input from stakeholders. The Commission has recognized the critical role that stakeholders serve in effective transmission planning,³³⁵⁹ and in Order Nos. 890 and 1000, directed reforms to facilitate their meaningful participation in both local and regional transmission planning.³³⁶⁰ However, the record demonstrates that existing transparency and coordination requirements in local transmission planning do not consistently provide stakeholders with sufficient information regarding the development of local transmission plans.³³⁶¹ We further find that the

³³⁵⁹ See, e.g., Order No. 890, 118 FERC ¶ 61,119 at P 454 (“[C]ustomers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input.”); Order No. 1000, 136 FERC ¶ 61,051 at P 152 (“[A]bsent timely and meaningful participation by all stakeholders, the regional transmission planning process will not determine which transmission project or group of transmission projects could satisfy local and regional needs more efficiently or cost-effectively.”).

³³⁶⁰ See, e.g., Order No. 890, 118 FERC ¶ 61,119 at PP 454, 488, 557; Order No. 1000, 136 FERC ¶ 61,051 at P 152.

³³⁶¹ E.g., OMS Initial Comments at 15 (“OMS members have varying levels of oversight and visibility into the utility-driven, local planning processes that are incorporated into the overall MISO transmission expansion plan.”); Concerned Scientists ANOPR Initial Comments at 24–31 (discussing challenges obtaining information to

³³⁵⁰ NOPR, 179 FERC ¶ 61,028 at P 399 (citing *S. Cal. Edison Co.*, 164 FERC ¶ 61,160 at P 33; *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161, at P 68 (2018); *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136, at PP 12, 89 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at P 54 (2020)).

³³⁵¹ *Id.*

³³⁵² Dominion Initial Comments at 76 (citing NOPR, 179 FERC ¶ 61,028 at P 395 n.634); EEI Initial Comments at 40; Idaho Power Initial Comments at 12–13.

³³⁵³ EEI Initial Comments at 40; see also Dominion Initial Comments at 76.

³³⁵⁴ Idaho Power Initial Comments at 12–13.

³³⁵⁵ Indicated PJM TOs Initial Comments at 41 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 426–561).

³³⁵⁶ LS Power Initial Comments at 50–53 (citations omitted); NextEra Initial Comments at 54–56 (citations omitted). A number of commenters challenge the NOPR right-sizing proposal, including the proposal to permit a Federal right of first refusal for certain replacement facilities. We address those arguments below in the Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities section below.

³³⁵⁷ Competition Coalition Initial Comments at 64.

³³⁵⁸ Below, we clarify that the new transparency requirements do not apply to transmission facilities that are otherwise exempt from Order No. 890's transparency requirements, such as asset management projects. See *infra* Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process section.

absence of minimal standards or specified procedures to implement the transmission planning principles required by Order No. 890 contributes to inadequate transparency and opportunities for stakeholders to engage in local transmission planning processes.

1572. The combined effect of these deficiencies is that stakeholders who wish to participate in transmission planning, at both the local and regional level, may not be able to effectively do so. More specifically, we find that, when engaging in the regional transmission planning process, stakeholders lack sufficient information about underlying local transmission needs and potential solutions that is necessary to ensure that the more efficient or cost-effective regional transmission solutions are identified, evaluated, and selected. Given the recognized importance of stakeholder participation in effective transmission planning, we find that reforms are needed to ensure that Commission-jurisdictional local and regional transmission planning processes remain just, reasonable, and not unduly discriminatory or preferential. Furthermore, we believe that reforms to better ensure more consistent implementation of the Order No. 890 transmission planning principles are timely and important in light of the significant investments in transmission infrastructure that now occur through local transmission planning processes.³³⁶²

1573. Second, we find that additional coordination between the local and regional transmission planning processes regarding replacement of aging infrastructure is needed. The record shows that many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life. For example, we note that PJM estimated that roughly two-thirds of all PJM transmission system assets are more than 40 years old, with some transmission facilities approaching 90 years old.³³⁶³ NYISO highlights that 80

assess projects developed through local transmission planning processes) (citations omitted); New Jersey Commission ANOPR Initial Comments at 6–7 (discussing limited information and analysis provided regarding projects considered in local transmission planning) (citations omitted).

³³⁶² See *supra* The Overall Need for Reform section.

³³⁶³ See PJM Interconnection, L.L.C., *The Benefits of the PJM Transmission System* 5 (2019), <https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf>. Moreover, AEP estimates that approximately 30 percent of its line miles and circuit breakers will need to be replaced over the

percent of transmission lines in its footprint are at least 50 years old and are either being replaced or will soon need to be replaced.³³⁶⁴ Replacing these transmission facilities will require substantial investment, which will directly affect Commission-jurisdictional transmission rates. For example, the California Commission notes that PG&E anticipates spending roughly \$11 billion between 2022 and 2027 to address aging transmission infrastructure.³³⁶⁵

1574. However, because the Commission's existing requirements do not obligate transmission providers to share sufficient information regarding these replacement projects, transmission providers in the regional transmission planning process are not consistently evaluating whether those replacement transmission facilities could be modified (*i.e.*, right-sized) to more efficiently or cost-effectively address transmission needs. We therefore find that the lack of a requirement for transmission providers in each transmission planning region to evaluate whether those replacement transmission facilities could be modified (*i.e.*, right-sized) to more efficiently or cost-effectively address Long-Term Transmission Needs results in a regional transmission planning process that fails to identify opportunities to right-size planned in-kind replacement transmission facilities and may result in the development of inefficiently sized or designed, duplicative, or unnecessary transmission facilities that increase costs to customers and render Commission-jurisdictional rates unjust and unreasonable.

1575. With respect to the claim by commenters that the Commission lacks jurisdiction to impose the proposed transparency and coordination requirements or that the Commission has not justified the requirements,³³⁶⁶ we disagree. Consistent with Order Nos. 890 and 1000, the Commission has authority to establish requirements related to local transmission planning processes and the inputs to regional transmission planning processes.³³⁶⁷

next 10 years. See AEP, *Wolfe Utilities, Midstream, & Clean Energy Conference* 40 (Sept. 30, 2021), <https://www.aep.com/Assets/docs/investors/events/presentationsandwebcasts/WolfeConferencePresentation093021.pdf>.

³³⁶⁴ NYISO Initial Comments at 58.

³³⁶⁵ California Commission Initial Comments at 110.

³³⁶⁶ Dominion Initial Comments at 76; EEI Initial Comments at 40; Idaho Power Initial Comments at 12–13.

³³⁶⁷ See, *e.g.*, Order No. 890, 118 FERC ¶ 61,119 at P 435 (“In order to limit the opportunities for undue discrimination . . . and to ensure that

Our findings above are supported by substantial evidence in the record, and we address any concerns regarding our remedy to address the transparency and coordination deficiencies below.

1576. We also disagree with LS Power, Competition Coalition, and NextEra's arguments regarding whether the Commission properly demonstrated under FPA section 206 that existing rates are unjust, unreasonable, or unduly discriminatory or preferential in instituting a Federal right of first refusal for right-sized replacement transmission facilities.³³⁶⁸ First, we clarify that the Commission is not finding that existing transmission planning processes are unjust, unreasonable, or unduly discriminatory or preferential due to a lack of a Federal right of first refusal for these facilities. Rather, we find here that transmission providers' OATTs are unjust and unreasonable due to the lack of right-sizing requirements that may lead to the identification, evaluation, and selection of more efficient or cost-effective Long-Term Regional Transmission Facilities. As discussed above, the record demonstrates that many incumbent transmission providers are replacing aging transmission infrastructure as it reaches the end of its useful life without evaluating, through the regional transmission planning process, whether those replacement transmission facilities could be modified (*i.e.*, right-sized) to more efficiently or cost-effectively address transmission needs. As a result of this identified deficiency, we find that transmission providers' OATTs are unjust and unreasonable. We address LS Power, NextEra, and other commenters' concerns regarding the Commission's proposed replacement rate, including our findings regarding a Federal right of first refusal for right-sized replacement transmission facilities, below.

1577. Because we find that the Commission's existing requirements governing transparency in local transmission planning processes and coordination between local and regional transmission planning processes are insufficient to ensure just and reasonable and not unduly discriminatory or preferential rates, we are now requiring, pursuant to FPA section 206, that transmission providers

comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, the Commission concludes that it is necessary to amend the existing *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a local and regional level.”); Order No. 1000, 136 FERC ¶ 61,051 at PP 68, 148, 152.

³³⁶⁸ Competition Coalition Initial Comments at 64; LS Power Initial Comments at 51–53; NextEra Initial Comments at 54–56.

adopt, with certain modifications, the two reforms that the Commission identified in the NOPR: (1) enhance the transparency of local transmission planning processes; and (2) require transmission providers to evaluate whether transmission facilities that need replacing can be “right-sized” to more efficiently or cost-effectively address Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning.³³⁶⁹ We find that the first reform will result in transmission providers providing enhanced transparency for stakeholders while providing those same stakeholders with opportunities to more effectively engage in local and regional transmission planning processes. We find that the second reform will result in transmission providers identifying, evaluating, and selecting replacement transmission facilities that more efficiently or cost-effectively address Long-Term Transmission Needs. Taken together, we find that these reforms will ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

B. Enhanced Transparency of Local Transmission Planning Inputs in the Regional Transmission Planning Process

1. NOPR Proposal

1578. In the NOPR, the Commission proposed to require transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs with additional provisions to enhance transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through that process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs.³³⁷⁰ The Commission explained that transmission providers would be required to establish an iterative process that would provide stakeholders with meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process.³³⁷¹ The Commission proposed to require that the regional transmission planning process include at least three publicly-noticed stakeholder meetings concerning the local transmission planning process of each transmission provider that is a member of the

transmission planning region before a transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.³³⁷²

1579. Specifically, the Commission proposed to require transmission providers in each transmission planning region, prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review the criteria, assumptions, and models related to each transmission provider's local transmission planning (Assumptions Meeting). Next, no fewer than 25 calendar days after the Assumptions Meeting, transmission providers that are members of the transmission planning region would be required to convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting). Finally, the Commission proposed to require that, no fewer than 25 calendar days after the Needs Meeting, transmission providers that are members of the transmission planning region convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting). The Commission also proposed to require that all materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.³³⁷³

1580. The Commission preliminarily found that these proposed requirements will result in needed additional transparency into local transmission planning processes, which inform the regional transmission planning process in a transmission planning region.³³⁷⁴

2. Comments

a. Interest in Enhanced Transparency of Local Transmission Planning Inputs

1581. Many commenters support the NOPR proposal.³³⁷⁵ ITC argues that the

Commission's proposed transparency requirements strike an appropriate balance between the need for oversight and the need to timely address asset management needs.³³⁷⁶ Southeast PIOs state that closer coordination between the regional and local transmission planning processes would help to ensure that the local process does not dull the effectiveness of the regional process.³³⁷⁷ Vermont State Entities support enhancing transparency and visibility of local transmission planning processes and coordinating with Long-Term Regional Transmission Planning and other processes, including the generator interconnection process.³³⁷⁸ City of New Orleans Council states that increased transparency, collaboration, and coordination between the regional and local transmission planning processes will result in more efficient local transmission development.³³⁷⁹ OMS asserts that enhanced transparency will enable retail regulators to more effectively participate in identifying the best set of projects to meet both local and regional needs.³³⁸⁰

1582. Colorado Consumer Advocates state that the Commission must ensure that transmission providers maintain coordinated, open, and transparent transmission planning processes on both a local and regional level that meet stakeholder needs.³³⁸¹ Interwest asserts that the NOPR proposal is needed to incentivize the coordination of generation and resource planning and transmission planning beyond state lines, adding that transparency measures, such as a process for information sharing, could allow customers or stakeholders to evaluate or replicate the findings from transmission

Energy Associations Initial Comments at 36; Clean Energy Buyers Initial Comments at 33; Colorado Consumer Advocates Initial Comments at 30–31; Cross Sector Representatives Supplemental Comments at 1; Exelon Initial Comments at 3, 51–52; Indicated PJM TOs Initial Comments at 40; Interwest Initial Comments at 17–18; ITC Initial Comments at 45–47; National and State Conservation Organizations Initial Comments at 2; New York Transco Initial Comments at 1; NextEra Initial Comments at 66–67; Northwest and Intermountain Initial Comments at 20; OMS Initial Comments at 16; PJM States Initial Comments at 4–6; Resale Iowa Initial Comments at 8; Resale Iowa Reply Comments at 5; SEIA Initial Comments at 25–26; Shell Initial Comments at 34; Southeast PIOs Initial Comments at 54–55; Vermont State Entities Initial Comments at 10.

³³⁷⁶ ITC Initial Comments at 45–47 (citations omitted).

³³⁷⁷ Southeast PIOs Initial Comments at 54–55.

³³⁷⁸ Vermont State Entities Initial Comments at 10 (citing NOPR, 179 FERC ¶ 61,028 at P 400).

³³⁷⁹ City of New Orleans Council Initial Comments at 11.

³³⁸⁰ OMS Initial Comments at 16.

³³⁸¹ Colorado Consumer Advocates Initial Comments at 17, 20–21.

³³⁶⁹ NOPR, 179 FERC ¶ 61,028 at PP 400–403.

³³⁷⁰ NOPR, 179 FERC ¶ 61,028 at P 400.

³³⁷¹ *Id.*

³³⁷² *Id.*

³³⁷³ *Id.* P 401.

³³⁷⁴ *Id.* P 402.

³³⁷⁵ See AEE Initial Comments at 3; AEP Reply Comments at 10; APPA Initial Comments at 47; Breakthrough Energy Initial Comments at 19; Center for Biological Diversity Initial Comments at 28; Certain TDUs Initial Comments at 13; City of New Orleans Council Initial Comments at 11; Clean

providers and reduce after-the-fact disputes regarding allocated costs.³³⁸²

1583. Exelon and Indicated PJM TOs note that the NOPR proposal mirrors PJM TOs' local transmission planning process.³³⁸³ Indicated PJM TOs state that the NOPR proposal will help to ensure the coordination of local and regional transmission planning while preserving transmission owner responsibility for local transmission planning.³³⁸⁴ Indicated PJM TOs state that the PJM Attachment M–3 process avoids duplication of projects between local and regional transmission planning processes.³³⁸⁵ Clean Energy Associations state that each transmission planning region should have the opportunity to regularly review local transmission planning criteria for consistency with regional transmission planning, as PJM's manuals require.³³⁸⁶

1584. Clean Energy Buyers state that existing local transmission planning has not met expectations for openness, coordination, and transparency, and that the NOPR proposal will help remedy such deficiencies and better identify cost-effective transmission projects.³³⁸⁷ Northwest and Intermountain agree that the Commission should reform local transmission planning processes to enhance transparency and provide meaningful opportunities for public input.³³⁸⁸ Similarly, Resale Iowa asserts that MISO's stakeholder processes do not address local transmission planning issues, especially those related to asset management, end-of-life, and other forms of local transmission planning that are exempt from Order No. 890's transmission planning requirements. Thus, Resale Iowa contends, its members believe they must bear the cost of new or upgraded transmission facilities without the opportunity to discuss less costly alternatives.³³⁸⁹

1585. National and State Conservation Organizations suggest that early and consistent community engagement are key elements to successful development

and timely completion of transmission projects, as the voices and concerns of affected local communities must be heard and acted upon to prevent environmental injustices and environmental damage.³³⁹⁰ WE ACT states that, in addition to coordination with state entities, there must also be meaningful engagement and robust input from affected and overburdened communities so that states and transmission providers are aware of the potential harms of siting transmission projects in environmental justice communities. WE ACT recommends that the Commission, its Office of Public Participation, state officials, and transmission providers familiarize themselves with several key documents relating to environmental justice to ensure meaningful community engagement and to inform comprehensive environmental justice analyses to reduce or eliminate undue burdens.³³⁹¹

b. Suggested Modifications to the NOPR Proposal

1586. Some commenters support the NOPR proposal, but also suggest modifications to make it more effective or request that the Commission provide flexibility for transmission planning regions to determine the best manner to meet the requirements.³³⁹² NARUC requests flexibility for transmission planning regions to determine the timeline for stakeholder processes.³³⁹³ NRECA requests that the Commission allow transmission planning regions that currently have transparent processes to maintain them.³³⁹⁴

1587. TANC encourages the Commission to provide regional

flexibility by allowing transmission providers to propose on compliance alternative frameworks for consideration of local transmission plans in the regional transmission planning process and allow transmission planning regions to consider the burden versus benefit of such as a requirement to maximize transparency and project efficiencies.³³⁹⁵

1588. NESCOE contends that aspects of the proposal are too prescriptive, such as the Commission dictating the number of stakeholder meetings. However, NESCOE states that enhanced transparency could help states and ratepayers better understand proposed transmission facilities and the costs associated with them.³³⁹⁶ NESCOE states that stakeholders should have meaningful opportunities to participate and provide feedback on local transmission planning throughout the regional transmission planning process, asserting that transmission owners in ISO–NE currently do little more than present their proposals for in-kind replacements of existing transmission infrastructure to ISO–NE's Planning Advisory Committee.³³⁹⁷

1589. ACOE states that the proposed stakeholder involvement in local transmission planning is beneficial but that the NOPR proposal lacks clarity on whether transmission providers must consider local transmission projects alongside other options in Long-Term Regional Transmission Planning.

1590. Joint Consumer Advocates argue that, while the NOPR proposal will increase transparency, it will not address the inability of consumer advocates to meaningfully review planning inputs or models because the inputs are not maintained in a format that enables stakeholders to review them, understand the assumptions, or replicate the transmission planning results, as contemplated in Order No. 890.³³⁹⁸ Pine Gate recommends that the Commission require that transmission providers make available to stakeholders information about the local transmission planning process for review and comment prior to the finalization or approval of the local transmission plan.³³⁹⁹

³³⁸² Interwest Initial Comments at 17–18. As an example, Interwest cites WestConnect's Colorado Coordinated Planning Group, which conducts transmission planning through task forces and work groups consisting of stakeholders. *Id.*

³³⁸³ Exelon Initial Comments at 3–4, 51–52 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0)); *see* Indicated PJM TOs Initial Comments at 42–43.

³³⁸⁴ Indicated PJM TOs Initial Comments at 42–43.

³³⁸⁵ *Id.* at 42.

³³⁸⁶ Clean Energy Associations Initial Comments at 37 (citing PJM Manual 14B, section 1.1 Planning Process Work Flow).

³³⁸⁷ Clean Energy Buyers Initial Comments at 33.

³³⁸⁸ Northwest and Intermountain Initial Comments at 20.

³³⁸⁹ Resale Iowa Reply Comments at 4–5.

³³⁹⁰ National and State Conservation Organizations Initial Comments at 2.

³³⁹¹ WE ACT Initial Comments at 5–6 (citing U.S. Env't Prot. Agency, *Promising Practices for EJ Methodologies in NEPA Reviews* (Mar. 2016), <https://www.epa.gov/environmentaljustice/ej-iwg-promising-practices-ej-methodologies-nepa-reviews>; U.S. Env't Prot. Agency, *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis* (June 2016), https://www.epa.gov/sites/default/files/2016-06/documents/ejtg_5_6_16_v5.1.pdf; *The Principles of Environmental Justice (EJ)*, Energy Justice Network, <https://www.ejnet.org/ej/principles.pdf>; *Jemez Principles of Democratic Organizing*, Energy Justice Network, <https://www.ejnet.org/ej/jemez.pdf>).

³³⁹² *See* ACOE Initial Comments at 18–19; AEP Initial Comments at 7, 40–41, 43–44; Ameren Initial Comments at 46–47; NARUC Initial Comments at 58–59; NESCOE Initial Comments at 77–78; North Carolina Commission and Staff Initial Comments at 18–20; NRECA Initial Comments at 65–66; NYISO Initial Comments at 9, 57–58; TANC Initial Comments at 11; WE ACT Initial Comments at 5–6; WIRES Initial Comments at 8–10.

³³⁹³ NARUC Initial Comments at 58–59 (citing NOPR, 179 FERC ¶ 61,028 at PP 400–401).

³³⁹⁴ NRECA Initial Comments at 65–66; *see also* Ameren Initial Comments at 46 (citing Ameren ANOPR Initial Comments at 20–21).

³³⁹⁵ TANC Initial Comments at 11 (citing NOPR, 179 FERC ¶ 61,028 at PP 400, 402).

³³⁹⁶ NESCOE Initial Comments at 77–78 (citing NOPR, 179 FERC ¶ 61,028 at P 400).

³³⁹⁷ *Id.*; NESCOE Reply Comments at 6 (citation omitted).

³³⁹⁸ Joint Consumer Advocates Initial Comments at 21–22.

³³⁹⁹ Pine Gate Initial Comments at 49–50.

c. Concern With the NOPR Proposal

1591. Several commenters state that they oppose or have concerns with the NOPR proposal.³⁴⁰⁰ Ohio Commission Federal Advocate argues that the NOPR proposal is of limited value given that it does not require a more comprehensive review of local transmission projects; instead, these projects will continue to be chosen, designed, and approved by the transmission owner.³⁴⁰¹ Similarly, American Municipal Power states that new transmission projects that expand or enhance the transmission grid and have regional benefits should be planned by the regional transmission entity and not by individual transmission owners. Further, American Municipal Power asserts that use of the PJM Attachment M-3 process, which American Municipal Power contends the NOPR “essentially” proposes to require nationwide, has resulted in additional balkanization of the transmission planning process, has increased the problem of planning based on individual transmission owners’ criteria for determining need, and has disenfranchised PJM as the regional transmission planner.³⁴⁰²

1592. Relatedly, Pennsylvania Commission states that enhancing transparency in local transmission planning is a laudable goal but notes that the proposal will not enhance PJM’s process because the NOPR proposal adopts the existing PJM Attachment M-3 process.³⁴⁰³

1593. Several commenters argue that the existing regional transmission planning process in their transmission planning region is already transparent and therefore oppose the NOPR proposal.³⁴⁰⁴ New York TOs assert that

New York’s regional and local transmission planning processes almost fully satisfy the proposed requirements and, as such, the Commission should allow NYISO to retain these processes.³⁴⁰⁵ MISO argues that the additional requirements proposed in the NOPR are not needed in an RTO such as MISO with a fully developed, open, and transparent transmission planning process in effect.³⁴⁰⁶ MISO TOs agree, stating that MISO’s existing processes provide for transparency in local transmission planning through subregional planning meetings, published materials, and workshops throughout the transmission planning process.³⁴⁰⁷

1594. CAISO states that the Commission should not disrupt existing processes that are working efficiently, arguing that its transmission planning process already considers both local and regional assumptions, needs, and solutions as part of a single integrated process.³⁴⁰⁸ PG&E agrees that the NOPR proposal is unnecessary for California utilities and CAISO because many CAISO transmission owners already have extensive stakeholder programs. Therefore, PG&E states, the Commission should clarify that transmission providers are not required to enhance the transparency of local transmission planning processes where such transparent processes already exist.³⁴⁰⁹

1595. In addition, PG&E argues that the Commission should revise the NOPR proposal to state that the proposed enhancements to the local transmission planning process should not apply to asset management projects, including in-kind replacements, that are outside the scope of Order No. 890.³⁴¹⁰ PG&E asserts that including asset

management projects would significantly increase the volume and complexity of regional and local transmission planning and potentially delay needed repairs and maintenance. PG&E further states that all of PG&E’s asset replacement projects are already scrutinized through the annual update to its formula transmission rate.³⁴¹¹

1596. Eversource contends that the current local transmission planning process in New England, which is based on the principles in Order No. 890, is largely consistent with the Commission’s proposed transparency principles and has worked well.³⁴¹² Similarly, APS states that it currently uses its local transmission plans in the base model assumptions for its regional transmission planning process and provides stakeholders with an opportunity for input twice a year in public meetings as required by Order No. 890.³⁴¹³

1597. Some commenters request that the Commission adopt a less prescriptive reform that outlines principles or goals for transparency and allow each transmission provider to either explain how its existing local transmission planning process already complies with those principles or propose targeted modifications to bring its existing process into compliance with the new requirements.³⁴¹⁴ New York TOs note that efforts to improve transparency between local and regional transmission planning are beginning in NYISO, and they recommend that the Commission allow NYISO and New York TOs to demonstrate on compliance how any resulting enhancements will meet or exceed any new requirements.³⁴¹⁵ Vermont Electric and Vermont Transco suggest that the Commission adopt a performance-based approach under which the Commission would specify expectations for transparency in local transmission planning processes and then allow transmission providers to determine how they will achieve those goals within longer timelines.³⁴¹⁶

³⁴⁰⁰ See American Municipal Power Initial Comments at 13–25; APS Initial Comments at 12–13; Avangrid Initial Comments at 13–15; CAISO Initial Comments at 7, 47–51; California Water Initial Comments at 5–8; DC and MD Offices of People’s Counsel Initial Comments at 6–7; Dominion Initial Comments at 69–70; EEI Initial Comments at 40; Eversource Initial Comments at 47–49; Idaho Power Initial Comments at 12–13; MISO Initial Comments at 84–86; MISO TOs Initial Comments at 28–31; National Grid Initial Comments at 39–40; New York TOs Initial Comments at 16–17; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 15–18; PPL Initial Comments at 35–36; Xcel Initial Comments at 16–17.

³⁴⁰¹ See Ohio Commission Federal Advocate Initial Comments at 20–21 (citing NOPR, 179 FERC ¶ 61,028 (Christie, Comm’r, concurring at P 16)).

³⁴⁰² American Municipal Power Initial Comments at 17; see American Municipal Power Supplemental Comments at 1, 6 (citations omitted).

³⁴⁰³ Pennsylvania Commission Initial Comments at 20–21 (citing NOPR, 179 FERC ¶ 61,028 at PP 399–400).

³⁴⁰⁴ APS Initial Comments at 12–13; Avangrid Initial Comments at 13–15; CAISO Initial

Comments at 46–50; Dominion Initial Comments at 69; Eversource Initial Comments at 46–49; MISO Initial Comments at 84–86; MISO TOs Initial Comments at 29–31; National Grid Initial Comments at 39; New York TOs Initial Comments at 16–17; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 16–18.

³⁴⁰⁵ New York TOs Initial Comments at 7.

³⁴⁰⁶ MISO Initial Comments at 84–85.

³⁴⁰⁷ MISO TOs Initial Comments at 29–31 (citing MISO Business Practice Manual, Transmission Planning, BPM-20, section 4.1; MISO, FERC Electric Tariff, MISO OATT, attach. FF (Transmission Expansion Planning Protocol) (90.0.0), § I.C.9; MISO, *Subregional Planning Meeting*, <https://www.misoenergy.org/engage/committees/subregional-planning-meeting/>; *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 FERC ¶ 61,215, at PP 80, 114 (2013), *order on reh’g*, 144 FERC ¶ 61,020 (2013), *order on reh’g & compliance*, 147 FERC ¶ 61,127 (2014), *aff’d sub nom. MISO Transmission Owners v. FERC*, 819 F.3d 329 (7th Cir. 2016)).

³⁴⁰⁸ CAISO Initial Comments at 47–50 (citations omitted).

³⁴⁰⁹ PG&E Initial Comments at 15–18.

³⁴¹⁰ *Id.* at 15–16 (citing *Cal. Pub. Utils. Comm’n v. Pac. Gas & Elec.*, 164 FERC ¶ 61,161 at P 66).

³⁴¹¹ PG&E Reply Comments at 6–7.

³⁴¹² Eversource Initial Comments at 46–47 (citing *ISO New England, Inc.*, Transmittal, Docket No. OA08–58 (filed Dec. 7, 2007)).

³⁴¹³ APS Initial Comments at 12 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 257–258, 451).

³⁴¹⁴ See Avangrid Initial Comments at 15; EEI Initial Comments at 40; Eversource Initial Comments at 48; Kansas Commission Initial Comments at 17; MISO Initial Comments at 84; MISO TOs Initial Comments at 31; National Grid Initial Comments at 39; New York TOs Initial Comments at 7, 16–17; Xcel Initial Comments at 17.

³⁴¹⁵ See New York TOs Initial Comments at 6–7, 16–17 (citations omitted).

³⁴¹⁶ Vermont Electric and Vermont Transco Initial Comments at 5.

1598. Several commenters argue that the NOPR proposal is too prescriptive or may interfere with existing processes.³⁴¹⁷ Eversource states that, if the Commission adopts a more prescriptive approach to local transmission planning, it could conflict with existing, state-jurisdictional planning processes for local transmission projects, creating barriers to distribution facility upgrades that are needed to support expanded use of distributed energy resources and load growth from electrification.³⁴¹⁸ Dominion cautions against adding more process when transmission providers already participate in extensive local transmission planning processes that consider Long-Term Regional Transmission Planning and stakeholder positions.³⁴¹⁹ Avangrid agrees, asserting that the NOPR proposal could override existing processes that have been established over years of stakeholder consensus building.³⁴²⁰ PPL and American Municipal Power state that the NOPR proposal may not be appropriate for all transmission planning regions and may interfere with efficient and well-functioning local transmission planning.³⁴²¹

1599. Certain commenters also argue that the NOPR proposal is unduly burdensome.³⁴²² APS argues that the NOPR proposal could delay local transmission planning and prevent APS from providing necessary services.³⁴²³ National Grid asserts that the NOPR proposal ignores the reality that local transmission planning processes address different needs than the regional transmission planning process. National Grid argues that the proposal will introduce delay and uncertainty in both the local and regional transmission planning processes, disrupting currently effective procedures at a time when participants in the regional transmission planning process should be focused on Long-Term Regional Transmission Planning.³⁴²⁴

1600. In addition, National Grid argues that the NOPR proposal will

complicate transmission planning because individual transmission providers in each transmission planning region will need to integrate their local transmission planning efforts into the regional transmission planning process. Further, National Grid states that in multi-state RTO/ISO transmission planning regions, it could also lead to second guessing individual state policies as part of the regional transmission planning process. National Grid also avers that regional transmission planners, such as NYISO and ISO-NE, may not have visibility into the operation of lower voltage local transmission facilities and therefore may not have the expertise that is needed to consider local transmission needs as part of the regional transmission planning process.³⁴²⁵

d. Specific Stakeholder Meeting Requirements

1601. With respect to the length of time between stakeholder meetings, some commenters state that the 25-day minimum period between meetings in the NOPR proposal is too short.³⁴²⁶ PIOs state the Commission should require transmission providers to submit local transmission planning information, including information concerning planned local transmission projects, with enough time for the regional transmission planning process to effectively find, propose, approve, and construct cost-effective and beneficial regional alternatives where appropriate.³⁴²⁷

1602. American Municipal Power contends that the NOPR proposal fails to identify whether and when transmission providers must provide information in advance of the three meetings. Moreover, American Municipal Power argues, 25 days between meetings is too short, even assuming all of the models, criteria, and needs are shared with stakeholders sufficiently in advance. Further, American Municipal Power states that the time between the Needs and Solutions Meetings should be based on the time required for transmission providers to incorporate comments received during the Needs Meeting and develop responses.³⁴²⁸

1603. Eversource argues that the proposed meeting schedules are not

workable in New England, where regional transmission planning studies focus on sub-areas of the transmission system and proceed on different timelines. Moreover, Eversource contends that it is not feasible in New England to have a three-meeting process that aligns with ISO-NE's annual transmission planning cycle because no such annual planning cycle exists.³⁴²⁹

1604. Dominion, Eversource, and Xcel state that the three separate stakeholder meetings to review assumptions, needs, and solutions are unnecessary and will increase workload without any benefit.³⁴³⁰ Xcel contends that a single meeting that addresses the transparency requirements of Order Nos. 890 and 1000, as well as any requirements from the final order, would be more efficient than the NOPR proposal.³⁴³¹ NESCOE asserts that the final order should not dictate the number of stakeholder meetings.³⁴³² MISO states that the Commission should allow each transmission planning region to determine the timing of the iterative meetings, as well as the specific information to be covered at the meetings.³⁴³³

1605. TAPS states that the Commission should require transmission providers to post their criteria, models, and assumptions so that stakeholders can evaluate or replicate their findings. Moreover, TAPS argues, the Commission should require that transmission providers distribute this information "sufficiently in advance" (and not just "in advance," as the NOPR proposed) of each meeting to allow stakeholders to review and evaluate the information.³⁴³⁴ Finally, TAPS states that a second Solutions Meeting would provide a meaningful opportunity to consider alternatives.³⁴³⁵

1606. Likewise, American Municipal Power recommends that the Commission require a minimum of two Solutions Meetings, with the transmission provider presenting the solutions at the first meeting and the final solution, including alternatives considered, at the second. Further, American Municipal Power recommends that the first Solutions Meeting be no sooner than 90 days after the Needs Meeting and the second

³⁴¹⁷ Avangrid Initial Comments at 13; CAISO Initial Comments at 7–8, 47, 50; Dominion Initial Comments at 70; Eversource Initial Comments at 47–48; MISO Initial Comments at 86; PG&E Initial Comments at 17–18; PPL Initial Comments at 36; Xcel Initial Comments at 16–17.

³⁴¹⁸ Eversource Initial Comments at 49.

³⁴¹⁹ Dominion Initial Comments at 69–70.

³⁴²⁰ Avangrid Initial Comments at 13.

³⁴²¹ American Municipal Power Initial Comments at 16; PPL Initial Comments at 36.

³⁴²² See Dominion Initial Comments at 68; Eversource Initial Comments at 49; National Grid Initial Comments at 39–40; Xcel Initial Comments at 16–17.

³⁴²³ APS Initial Comments at 13.

³⁴²⁴ National Grid Initial Comments at 39–40.

³⁴²⁵ *Id.*

³⁴²⁶ American Municipal Power Initial Comments at 24; Northwest and Intermountain Initial Comments at 21; PIOs Initial Comments at 51–54; TAPS Initial Comments at 6, 62.

³⁴²⁷ PIOs Initial Comments at 51–52, 54 (citing PIOs ANOPR Initial Comments at 92–94; Concerned Scientists ANOPR Initial Comments at 24–31).

³⁴²⁸ American Municipal Power Initial Comments at 24.

³⁴²⁹ Eversource Initial Comments at 47.

³⁴³⁰ Dominion Initial Comments at 68; Eversource Initial Comments at 47–48; Xcel Initial Comments at 17.

³⁴³¹ Xcel Initial Comments at 16–17.

³⁴³² NESCOE Initial Comments at 78 (citation omitted).

³⁴³³ MISO Initial Comments at 84.

³⁴³⁴ TAPS Initial Comments at 61 (citing NOPR, 179 FERC ¶ 61,028 at P 402).

³⁴³⁵ *Id.* at 62.

Solutions Meeting no sooner than 30 days after the first Solutions Meeting. To the extent the Commission does not require a second Solutions Meeting, American Municipal Power recommends that it require transmission providers to provide additional clarity regarding how alternatives were developed and why they were not selected during the single Solutions Meeting.³⁴³⁶

1607. While PJM States support requiring Assumptions, Needs, and Solutions Meetings as part of local transmission planning processes, similar to PJM's existing Attachment M-3 process, they express concern that PJM's process is not sufficiently responsive and that the growth of transmission-related costs in PJM is occurring without effective oversight.³⁴³⁷ PJM States reference PJM's requirement that transmission providers provide information on their local transmission plan and consider any comments received, but state that they are not required to "meaningfully respond to, engage with, or incorporate" these comments.³⁴³⁸

1608. California Commission notes that the key elements of the California stakeholder processes that may be relevant for the Commission to consider including in a final order to increase transparency into local transmission planning include: (1) detailed project and capital expenditure data; (2) ample time to review proposed capital forecasts; (3) the ability for stakeholders to issue data requests and receive responses; (4) in-depth stakeholder meetings; and (5) consideration of stakeholder comments.³⁴³⁹

1609. New England for Offshore Wind argues that all transmission planning processes should include transparency into the evaluation of alternative options that could optimize the performance of renewable energy, as well as justification of proposed transmission projects based on how they compare to no action alternatives.³⁴⁴⁰ NRG encourages the Commission to require that the local transmission planning process produce an estimated rate impact for each year if the local

transmission plan were to be executed.³⁴⁴¹

1610. Several commenters contend that transmission providers should be required to respond to comments and questions submitted by stakeholders in the local transmission planning process.³⁴⁴² PJM States raise the same issue but look to the relevant RTOs/ISOs to resolve them.³⁴⁴³

1611. American Municipal Power and DC and MD Offices of People's Counsel state that transmission providers are not obligated to respond to stakeholder questions, which, when considered alongside the other barriers to effective participation, creates unnecessary barriers to open communication, is not just and reasonable, and is unduly discriminatory.³⁴⁴⁴ American Municipal Power further asserts that comparability principles require transmission providers to consider transmission customers' comments in order to meet their needs and to treat similarly situated customers comparably while conducting transmission system planning.³⁴⁴⁵ However, PJM and Indicated PJM TOs disagree that stakeholder comments are being ignored in PJM's Attachment M-3 process.³⁴⁴⁶

1612. TAPS states that dispute resolution on criteria, assumptions, needs, and proposed solutions should be available if stakeholder comments are ignored.³⁴⁴⁷ TAPS asserts that the Commission should include such provisions in any final order or clarify that they are already encompassed in the Commission's transparency proposal.³⁴⁴⁸

e. Additional Issues

1613. Pattern Energy and American Municipal Power state that the NOPR proposal does not go far enough in ensuring stakeholder access to transmission planning data from the local transmission planning processes and propose additional requirements to

make certain information more readily available, subject to execution of a CEII non-disclosure agreement.³⁴⁴⁹ Similarly, Pattern Energy states that continued stakeholder access to the source data used in transmission modeling by transmission providers is essential to ensure fair and reasonable outcomes in any transmission planning process.³⁴⁵⁰ PPL requests that the Commission clarify that confidential or sensitive information will be protected under the NOPR proposal in the local transmission planning processes as they currently are in PJM.³⁴⁵¹

1614. Certain TDUs state that the Commission should require transmission providers to coordinate with load-serving entities to transfer data and information and increase transparency in the stakeholder process.³⁴⁵² ACEG recommends that the Commission require minimum data transparency standards in the local transmission planning processes, drawing on MISO's and SPP's cost recording and tracking processes for transmission projects approved through their regional transmission planning processes.³⁴⁵³ Maryland Energy Administration asserts that additional reforms beyond those proposed in the NOPR are needed to support transparency and better incorporate stakeholder contributions in local transmission planning processes.³⁴⁵⁴ California Water recommends that the Commission allow data requests, similar to the opportunity for data requests in the SoCal Edison and PG&E stakeholder review processes, which ensure that stakeholders can participate and that transmission providers exercise good faith efforts to respond.³⁴⁵⁵

1615. American Municipal Power requests that the Commission direct transmission providers to provide detailed information consisting of more than generic or high-level network models, along with power flow models and power system analyses used in their

³⁴³⁶ American Municipal Power Initial Comments at 24–25.

³⁴³⁷ PJM States Initial Comments at 4–5 (citing PJM, *2021 Regional Transmission Planning Expansion Plan* 290 (Mar. 2022), <https://www.pjm.com/-/media/library/reports-notice/2021-rtep/2021-rtep-report.ashx>).

³⁴³⁸ *Id.* at 6 (citing PJM, *Intra-PJM Tariffs*, OATT, attach. M-3 (1.0.0), section (c) 1–6).

³⁴³⁹ California Commission Initial Comments at 112–113.

³⁴⁴⁰ New England for Offshore Wind Initial Comments at 6.

³⁴⁴¹ NRG Initial Comments at 7, 36.

³⁴⁴² See American Municipal Power Initial Comments at 18–19; California Commission Initial Comments at 112–113; DC and MD Offices of People's Counsel Initial Comments at 6; Kentucky Commission Chair Chandler Initial Comments at 22; Northwest and Intermountain Initial Comments at 20–21; TAPS Initial Comments at 62.

³⁴⁴³ PJM States Initial Comments at 6.

³⁴⁴⁴ See American Municipal Power Initial Comments at 19–20; DC and MD Offices of People's Counsel Initial Comments at 6–7.

³⁴⁴⁵ American Municipal Power Initial Comments at 19.

³⁴⁴⁶ Indicated PJM TOs Reply Comments at 4, 18–19 (citations omitted); PJM Reply Comments at 13–15 (citing American Municipal Power Initial Comments at 19).

³⁴⁴⁷ TAPS Initial Comments at 62 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 501–503).

³⁴⁴⁸ *Id.*

³⁴⁴⁹ See American Municipal Power Initial Comments at 22; Pattern Energy Initial Comments at 30–31.

³⁴⁵⁰ Pattern Energy Initial Comments at 30–31.

³⁴⁵¹ PPL Initial Comments at 36.

³⁴⁵² Certain TDUs Initial Comments at 18.

³⁴⁵³ ACEG Initial Comments at 56 (citing Johannes Pfeifenberger et al., *The Brattle Group, Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* 26 (Apr. 2019)).

³⁴⁵⁴ See Maryland Energy Administration Reply Comments at 2–3 (citations omitted).

³⁴⁵⁵ California Water Initial Comments at 7–8 (citing *S. Cal. Edison*, Filing, App. XII, ER19–1553–000, at section 2.2 (filed July 2, 2020); *Pac. Gas & Elec. Co.*, Filing, App. IX, ER19–13–001, at section 3.2 (filed Mar. 31, 2020)).

local transmission planning.³⁴⁵⁶ According to American Municipal Power, to allow stakeholders to evaluate the outputs of transmission providers' studies—*i.e.*, the identified transmission needs—on their own, transmission providers must be required to provide the models.³⁴⁵⁷ Furthermore, American Municipal Power argues, the Commission should require transmission providers to provide information on how assets have been prioritized for replacement, how the replacement versus maintenance decision is made, how assets rank relative to other assets on the system, and the system average values.³⁴⁵⁸

1616. Several commenters state that the NOPR proposal does not go far enough to protect customers' interests and suggest the addition of more process, more oversight, more monitoring (including establishing an independent transmission monitor), or more prudence reviews.³⁴⁵⁹ According to PIOs, transmission providers have incentives to avoid independent transmission planning processes because local transmission projects are presumed to be prudent, avoid competition, and receive high rates of return. PIOs state that the Commission should reduce the rate of return for local transmission projects and issue a rule or policy statement that puts the burden of proof on transmission providers to demonstrate that the cost of a proposed transmission project is just and reasonable.³⁴⁶⁰

1617. Joint Consumer Advocates state that, while the NOPR proposal is an improvement, more needs to be done to address the imbalance between consumer advocates and incumbent transmission owners. Therefore, Joint Consumer Advocates assert, the Commission should authorize the creation of an independent transmission monitor to evaluate the effective coordination of local transmission projects with more holistic transmission planning to identify the most efficient or cost-effective approach to meeting local, regional, and interregional transmission

needs.³⁴⁶¹ Relatedly, California Commission and Colorado Consumer Advocates suggest that the Commission give independent transmission monitors the responsibility to evaluate stakeholder comments, independently analyze whether there are potentially more efficient and cost-effective alternative transmission solutions to meet identified transmission needs, and make a recommendation.³⁴⁶² Potomac Economics argues that the Commission's transparency goals likely cannot be met without an independent transmission monitor.³⁴⁶³

1618. Some commenters opine on whether the regional transmission planning process should assume an expanded role in reviewing or approving identified local transmission projects.³⁴⁶⁴ In addition, NARUC recommends that the Commission allow the proposed stakeholder review process to apply to repair and replacement projects that do not expand the capacity of the transmission system, or do so only incidentally, in particular those that are forecast to cost \$3 million or more. NARUC asserts that, limiting the reforms to local transmission planning may exclude review of these projects, which currently comprise half of investor-owned utilities' transmission spending in the RTOs/ISOs. Further, NARUC urges the Commission to allow these projects, along with local transmission projects, to be reviewed and approved as part of the regional transmission planning process.³⁴⁶⁵ California Commission agrees, stating that there should be more external scrutiny of such projects to reduce incumbent utilities' existing perverse incentive to overinvest in these types of projects due to their lack of external review.³⁴⁶⁶

1619. PJM States call on RTOs/ISOs to go beyond evaluating whether local transmission projects "do no harm" by actively taking a stance on such projects, discussing how this stance was reached, and by proposing transmission projects that may be the most cost-

effective.³⁴⁶⁷ However, PJM States ask the Commission to explicitly avoid impinging on state-jurisdictional processes.³⁴⁶⁸

1620. DC and MD Offices of People's Counsel and American Municipal Power assert that the remedy for the current lack of a requirement to incorporate or respond to stakeholder feedback in the local transmission planning process is an empowered regional transmission planner that is independent and incorporates meaningful participation from all stakeholders beginning with the determination of any transmission needs through the project selection phase.³⁴⁶⁹ Relatedly, Ohio Consumers state that the NOPR proposal leaves sole discretion in selection of transmission projects and the costs of the projects to transmission providers.³⁴⁷⁰

1621. However, some commenters defend the separation between local and regional transmission planning processes.³⁴⁷¹ For instance, AEP disagrees that transmission providers seek to build local transmission projects to circumvent the regional transmission planning process.³⁴⁷² According to AEP, local and regional transmission planning processes are not interchangeable because most local transmission facilities directly serve load and local utilities must address local needs when those needs are not addressed by a regional transmission facility in a cost-effective manner.³⁴⁷³ Nevertheless, AEP states, there can be an effective and efficient intersection between local and regional transmission planning, citing PJM's open and transparent local transmission planning process that requires coordination with the regional transmission planning process and in which PJM is an active participant.³⁴⁷⁴ Similarly, WIRES states that there are good reasons for maintaining a distinction between regional and local transmission planning, noting that the regional transmission planning process is directed toward addressing certain

³⁴⁵⁶ American Municipal Power Initial Comments at 20–21.

³⁴⁵⁷ *Id.* at 21.

³⁴⁵⁸ *Id.* at 22–23.

³⁴⁵⁹ California Commission Initial Comments at 111–112 & n.401; Colorado Consumer Advocates Initial Comments at 31; Joint Consumer Advocates Initial Comments at 25–29; NRG Initial Comments at 7, 36; Ohio Consumers Initial Comments at 23–24; OMS Initial Comments at 16–17; Pattern Energy Initial Comments at 31–34; Pine Gate Initial Comments at 49–50; PIOs Initial Comments at 51–52; PJM States Initial Comments at 4–6; TAPS Initial Comments at 61–62; US DOJ and FTC Initial Comments at 20–21.

³⁴⁶⁰ PIOs Initial Comments at 52–53.

³⁴⁶¹ Joint Consumer Advocates Initial Comments at 26–29 (citations omitted).

³⁴⁶² California Commission Initial Comments at 111–112; Colorado Consumer Advocates Initial Comments at 31.

³⁴⁶³ See Potomac Economics Initial Comments at 6.

³⁴⁶⁴ See American Municipal Power Reply Comments at 3–7; California Commission Initial Comments at 108–110; DC and MD Offices of People's Counsel Initial Comments at 7; NARUC Initial Comments at 60–61; Ohio Consumers Reply Comments at 17–18; PJM States Initial Comments at 6–7.

³⁴⁶⁵ NARUC Initial Comments at 60–63 (citations omitted).

³⁴⁶⁶ California Commission Initial Comments at 109–110 (citations omitted).

³⁴⁶⁷ PJM States Initial Comments at 6–7 (citation omitted).

³⁴⁶⁸ *Id.* at 7.

³⁴⁶⁹ American Municipal Power Reply Comments at 3–7 (citations omitted); DC and MD Offices of People's Counsel Initial Comments at 7.

³⁴⁷⁰ Ohio Consumers Reply Comments at 18.

³⁴⁷¹ AEP Reply Comments at 6–7; MISO Reply Comments at 27; PG&E Reply Comments at 4–9; WIRES Initial Comments at 9.

³⁴⁷² AEP Reply Comments at 6–7 (citing AEE Initial Comments at 38; PIOs Initial Comments at 8–9; Resale Iowa Initial Comments at 7–8; US DOJ and FTC Initial Comments at 7).

³⁴⁷³ *Id.* at 2–3.

³⁴⁷⁴ *Id.* at 8 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0)).

reliability, economic criteria, and public policy initiatives, not the additional system needs related to resilience, asset management, customer needs, customer impact, and aging infrastructure replacement that are the focus of local transmission planning.³⁴⁷⁵

1622. Eversource states that, if the Commission decides to require a more prescriptive local transmission planning process, it should clarify that the process applies only to upgrades that are developed primarily to increase the capacity of the local transmission system, and not to upgrades that are incidental to state-jurisdictional distribution system planning or other unique local requirements.³⁴⁷⁶

1623. MISO defends the transparency of local transmission planning in MISO by stating that commenters who criticize existing local transmission planning processes “ignore the open, transparent process in effect, and fail to recognize the ongoing need for near-term planning.”³⁴⁷⁷ MISO states that local and regional transmission planning are complementary and that “near-, mid- and long-term planning work in concert.”³⁴⁷⁸ MISO contends that its existing process includes extensive stakeholder involvement that ensures that issues are identified and alternatives are considered.³⁴⁷⁹

1624. PG&E opposes comments in favor of removing the role of local transmission planning from local transmission owners, as well as requests to expand the NOPR proposal to apply to asset management projects. PG&E notes that California Commission has not provided any evidence that RTOs/ISOs are currently unable to adequately handle the regional and local transmission planning processes.³⁴⁸⁰

3. Commission Determination

1625. We adopt the NOPR proposal, with modification, to require transmission providers in each transmission planning region to revise the regional transmission planning process in their OATTs to enhance the transparency of: (1) the criteria, models, and assumptions that they use in their local transmission planning process; (2) the local transmission needs that they identify through the local transmission

planning process; and (3) the potential local or regional transmission facilities that they will evaluate to address those local transmission needs. For each of these three categories of local transmission planning information, and as discussed further below, transmission providers must identify and publicly post the information identified below, then conduct publicly-noticed stakeholder meetings to provide an opportunity for comment on the information both before and after the stakeholder meetings, as part of the regional transmission planning process. In response to comments from PG&E,³⁴⁸¹ we clarify that this requirement applies only to local transmission planning that is within the scope of Order No. 890 and is therefore already subject to Order No. 890 transparency requirements. As such, this requirement does not apply to asset management projects.³⁴⁸² However, nothing in this final order prevents transmission providers from choosing to apply these requirements to asset management projects.

1626. In complying with this requirement, transmission providers must establish an iterative process that ensures that stakeholders have meaningful opportunities to participate in and provide feedback on local transmission planning throughout the regional transmission planning process. To provide the needed transparency and opportunities for stakeholder participation, we require that the regional transmission planning process include at least three publicly-noticed stakeholder meetings per regional transmission planning cycle concerning the local transmission planning process of each transmission provider that is a member of the transmission planning region before each transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.

1627. Specifically, we adopt the NOPR proposal to require that, prior to the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process, transmission providers in each transmission planning region must convene, collectively, as

part of the regional transmission planning process, a stakeholder meeting to review the criteria, assumptions, and models related to each transmission provider's local transmission planning (Assumptions Meeting). Next, no fewer than 25 calendar days after the Assumptions Meeting, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review identified reliability criteria violations and other transmission needs that drive the need for local transmission facilities (Needs Meeting). Finally, no fewer than 25 calendar days after the Needs Meeting, transmission providers in each transmission planning region must convene, collectively, as part of the regional transmission planning process, a stakeholder meeting to review potential solutions to those reliability criteria violations and other transmission needs (Solutions Meeting). Additionally, we require that all materials for stakeholder review during these three meetings be publicly posted and that stakeholders have opportunities before and after each meeting to submit comments.

1628. In addition to these requirements, we modify the NOPR proposal to also require transmission providers to publicly post the meeting materials no fewer than five calendar days prior to each of the three publicly-noticed stakeholder meetings to allow time for stakeholders to review materials in advance of each meeting. Also, we require that transmission providers allow for a period of no fewer than 25 calendar days following the Solutions Meeting to review and consider stakeholder feedback on the local transmission solutions identified to meet the local transmission needs before the local transmission plan can be incorporated in the transmission planning region's planning models. Requiring this minimum 25 calendar day period is consistent with Order No. 1000, where the Commission stated that the Commission intends that the regional transmission planning processes provide for the timely and meaningful input and participation of stakeholders in the development of regional transmission plans.³⁴⁸³ Lastly, we require that transmission providers must respond to questions or comments from stakeholders such that it allows stakeholders to meaningfully participate in these three required stakeholder meetings.

³⁴⁷⁵ WIRES Initial Comments at 9 (citing Charles River Associates, *The Value of Local Transmission Planning* 9, 13 (Dec. 2021), <https://wiresgroup.com/wp-content/uploads/2021/12/Value-of-Local-Transmission-Planning-report-WIRES-CRA.pdf>).

³⁴⁷⁶ Eversource Initial Comments at 49.

³⁴⁷⁷ MISO Reply Comments at 27 (citing PIOs Initial Comments at 32).

³⁴⁷⁸ *Id.*

³⁴⁷⁹ *Id.*

³⁴⁸⁰ PG&E Reply Comments at 4–9 (citations omitted).

³⁴⁸¹ PG&E Initial Comments at 17 (citing *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec.*, 164 FERC ¶ 61,161 at P 66).

³⁴⁸² See *S. Cal. Edison Co.*, 164 FERC ¶ 61,160 at PP 30–40; *Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 at PP 65–74 (finding that Order No. 890's local transmission planning requirements do not apply to asset management projects that do not increase capacity or do so incidentally).

³⁴⁸³ Order No. 1000, 136 FERC ¶ 61,051 at P 153 (citing Order No. 890, 118 FERC ¶ 61,119 at P 454).

1629. We find that establishing a standard baseline of transparency into transmission providers' local transmission planning processes will ensure that stakeholders have an opportunity to review and provide feedback on local transmission planning assumptions, needs, and solutions that are used as inputs to the regional transmission planning process. We expect that this additional transparency will help reduce the possibility that transmission providers will develop local transmission facilities without adequately considering whether there is a more efficient or cost-effective regional transmission solution that could address their local transmission needs. This additional transparency will enable transmission providers to satisfy their requirements for regional transmission planning under Order No. 1000.³⁴⁸⁴

1630. We believe that the local transmission planning information provided pursuant to the enhanced transparency requirements that we adopt in this final order will better facilitate the identification through the regional transmission planning process of regional transmission facilities that may be more efficient or cost-effective than proposed local transmission facilities.³⁴⁸⁵ Specifically, transmission providers' local transmission planning information will be subject to review and comment by stakeholders that may provide additional information or identify considerations that could inform the criteria, models, and assumptions used in local transmission planning, the identification of local transmission needs, and the identification of transmission facilities to address those local transmission needs. Because local transmission planning information serves as an input to the regional transmission planning process, these improvements will, in turn, facilitate the identification of more efficient or cost-effective transmission facilities in the regional transmission planning process, resulting in Commission-jurisdictional rates that are just and reasonable and not unduly discriminatory or preferential.

1631. With respect to the comments from National and State Conservation Organizations and WE ACT³⁴⁸⁶ that robust input from affected and overburdened communities in the local transmission planning process is important, we believe that the added

transparency requirements that require transmission providers to identify and publicly post the information and then conduct stakeholder meetings as part of the regional transmission planning process, provides an opportunity for interested parties to engage and comment on the information.

1632. With regard to commenters that suggest that the additional transparency requirements proposed in the NOPR will not be effective because they do not go far enough in making changes to local transmission planning processes,³⁴⁸⁷ we find that the enhanced transparency requirements that we adopt in this final order are specifically designed to provide needed transparency to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential. In addition, we find that other commenters' suggestions for changes to local transmission planning processes were not proposed in the NOPR and therefore are outside the scope of this proceeding. We conclude that the replacement rate set forth herein is just and reasonable and addresses the deficiencies identified herein.³⁴⁸⁸ We note that the Commission continues to examine a suite of related issues in its Transmission Planning and Cost Management proceeding.³⁴⁸⁹

1633. In response to American Municipal Power's assertion that the PJM Attachment M-3 process has increased the problem of planning based on individual transmission owners' criteria and the balkanization of the transmission planning process,³⁴⁹⁰ we find that American Municipal Power has not persuasively explained why these concerns are the result of increasing the *transparency* of local transmission planning, rather than other factors associated with the PJM Attachment M-3 process. Based on the record before us, we do not expect that requiring enhanced transparency in local transmission planning, in the manner directed in this final order, will result in greater incentives for transmission providers to develop local transmission facilities in lieu of regional transmission facilities. Instead, we expect that additional opportunities for

stakeholder review of and comment on local transmission planning inputs into the regional transmission planning process will help to facilitate the identification of regional transmission facilities that are more efficient or cost-effective compared to transmission facilities identified in the local transmission planning process.

1634. We disagree with commenters that state that the NOPR proposal is not needed in their transmission planning region because their local transmission planning process is already sufficiently transparent.³⁴⁹¹ The reforms that we adopt here are necessary to ensure just and reasonable rates, as more fully explained above. Additionally, we believe that these reforms to enhance the transparency of local transmission planning inputs into the regional transmission planning process are necessary to ensure that interested stakeholders have an opportunity to meaningfully participate in the review of the local transmission planning assumptions, needs, and solutions before each transmission provider's local transmission plan can be incorporated into the transmission planning region's planning models.

1635. Similarly, we disagree with commenters that oppose the proposal because it may interfere with existing transmission planning processes.³⁴⁹² As we explain above, the enhanced transparency and opportunities for stakeholder participation are needed to ensure just and reasonable Commission-jurisdictional rates. Although we appreciate that there may be differences in how transmission providers currently conduct local transmission planning, we believe that the standard baseline of transparency established by the requirements adopted in this final order is needed to ensure that stakeholders have an opportunity to review and provide feedback on local transmission planning inputs that go into the regional transmission planning process and to ensure that the regional transmission planning process can identify regional transmission facilities that address transmission needs more efficiently or

³⁴⁹¹ APS Initial Comments at 12–13; Avangrid Initial Comments at 13–15; CAISO Initial Comments at 46–50; Dominion Initial Comments at 69–70; Eversource Initial Comments at 46–49; MISO Initial Comments at 84–86; MISO TOs Initial Comments at 29–31; National Grid Initial Comments at 39; New York TOs Initial Comments at 16; Pennsylvania Commission Initial Comments at 20; PG&E Initial Comments at 16–18.

³⁴⁹² Avangrid Initial Comments at 13; CAISO Initial Comments at 7, 47; Dominion Initial Comments at 70; Eversource Initial Comments at 47–48; MISO Initial Comments at 86; PG&E Initial Comments at 17–18; PPL Initial Comments at 36; Xcel Initial Comments at 16–17.

³⁴⁸⁷ See American Municipal Power Initial Comments at 17–18; Ohio Commission Federal Advocate Initial Comments at 19–20.

³⁴⁸⁸ See *New York v. FERC*, 535 U.S. at 26–28 (upholding Commission's decision not to assert jurisdiction over bundled retail transmission).

³⁴⁸⁹ See Transmission Planning and Cost Management, Notice of Technical Conference, Docket No. AD22–8–000 (Apr. 21, 2022).

³⁴⁹⁰ American Municipal Power Initial Comments at 17.

³⁴⁸⁴ *Id.* PP 78–84.

³⁴⁸⁵ NOPR, 179 FERC ¶ 61,028 at P 402.

³⁴⁸⁶ National and State Conservation Organizations Initial Comments at 2; WE ACT Initial Comments at 5–6.

cost-effectively than local transmission facilities. The fact that transmission providers may need to adjust their existing processes to comply with these requirements is not a sufficient reason for the Commission to decline to adopt them.

1636. We also disagree with commenters that argue that the proposal is too prescriptive.³⁴⁹³ We believe that these requirements strike a reasonable balance between the need for transparency of local transmission planning inputs that are used in regional transmission planning and providing transmission providers with flexibility in how they conduct their local transmission planning processes. In fact, experience with the PJM Attachment M–3 process, which includes similar requirements to those adopted in this final order, provides evidence that it is possible to satisfy these requirements with a process that allows transmission providers to produce their local transmission plans on a timely basis.³⁴⁹⁴ In response to National Grid’s concern that the NOPR proposal would impose a new requirement to integrate their local transmission planning with regional transmission planning,³⁴⁹⁵ the final order imposes no new requirements beyond the three meetings and associated opportunities for comment described above. We believe that these requirements add only a small but manageable burden for transmission providers, which is outweighed by the transparency benefits that would accrue to stakeholders participating in the local and regional transmission planning processes.

1637. With respect to the comments of APS and National Grid that local transmission planning cycles might be delayed by the new transparency requirements,³⁴⁹⁶ we reiterate that the final order strikes a reasonable balance between the need for transparency of local transmission planning inputs that are used in regional transmission planning and providing transmission providers with flexibility in how they conduct their local transmission planning processes. We believe that, even with the additional requirements

that we establish here, it is possible for transmission providers to produce local transmission plans within a 12-month period, especially given that when scheduling the three required meetings, transmission providers need not leave more than 25 calendar days between each meeting. The experience of PJM TOs, whose local transmission planning processes are subject to similar requirements, demonstrates that it is possible to satisfy these requirements in a timely manner.³⁴⁹⁷

a. Specific Stakeholder Meeting Requirements

1638. We address in this section the requirements specific to the implementation details associated with the three publicly-noticed stakeholder meetings that transmission providers are required to conduct: the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, that were discussed above. We believe that these requirements strike a reasonable balance between providing adequate time to allow interested stakeholders to review and comment on local transmission planning inputs that are used in regional transmission planning and allowing the efficient and timely execution of the local transmission planning process. In our view, allowing transmission providers to limit the length of time between the three required meetings accomplishes this balance.

1639. With respect to commenters who argue that a minimum of 25 calendar days between publicly-noticed stakeholder meetings is too short,³⁴⁹⁸ we disagree. The minimum period between stakeholder meetings is just that, a minimum, and we expect that transmission providers and their stakeholders will, in practice, implement a schedule for the required stakeholder meetings that best meets the needs of their transmission planning region. However, we find that a minimum of less than 25 calendar days between stakeholder meetings would not allow stakeholders to participate in a meaningful way, and we therefore adopt this minimum period as an appropriate baseline for providing stakeholders with a meaningful opportunity to review and comment on local transmission planning inputs that are used in regional transmission planning. And, in fact, at least some transmission providers have adopted

this minimum duration between stakeholder meetings.³⁴⁹⁹

1640. We clarify that transmission providers are required to provide information at least five calendar days prior to each of the three publicly-noticed stakeholder meetings. As stated above, transmission providers must publicly notice each meeting and publicly post all materials for stakeholder review during the three meetings and provide opportunities for stakeholders to submit comments before and after each meeting. We believe that providing this information at least five calendar days prior to each of the three stakeholder meetings strikes a balance between giving stakeholders meaningful opportunity to review the meeting materials ahead of each meeting and limiting the burden to transmission providers in posting the materials ahead of time. Furthermore, the information that we require transmission providers to share is information that they use in their local transmission planning processes and, thus, is information that they generally already possess.

1641. We disagree with commenters that argue that three separate publicly-noticed stakeholder meetings are unnecessary and will increase workload without any benefit, or that a single meeting would address the Commission’s transparency concerns more efficiently, or request that the Commission not dictate the number of stakeholder meetings.³⁵⁰⁰ We note that Indicated PJM TOs state that the PJM Attachment M–3 process has the benefit of avoiding duplication of projects between local and regional transmission planning processes.³⁵⁰¹ We also disagree with MISO’s argument that we should allow each transmission planning region to have complete discretion over the timing of the meetings, as well as the specific information to be covered at the meetings.³⁵⁰² While we allow flexibility in certain aspects of the transmission planning processes, we find that the requirement to hold three separate

³⁴⁹³ See Avangrid Initial Comments at 13–15; EEI Initial Comments at 40; Eversource Initial Comments at 47–48; Kansas Commission Initial Comments at 17; MISO Initial Comments at 84–86; MISO TOs Initial Comments at 29–31; National Grid Initial Comments at 39–41; New York TOs Initial Comments at 7, 16–17; Xcel Initial Comments at 17.

³⁴⁹⁴ See Indicated PJM TOs Initial Comments at 42–43 (citations omitted).

³⁴⁹⁵ National Grid Initial Comments at 39–40.

³⁴⁹⁶ APS Initial Comments at 13; National Grid Initial Comments at 39–40.

³⁴⁹⁷ Exelon Initial Comments at 3–4, 51–52 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0)); Indicated PJM TOs Initial Comments at 42–43.

³⁴⁹⁸ American Municipal Power Initial Comments at 24; Northwest and Intermountain Initial Comments at 21; TAPS Initial Comments at 6, 62.

³⁴⁹⁹ See PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0.), which, briefly, refers to the additional transparency and stakeholder input rules around transmission facilities that are not eligible for selection, but, though classified as local transmission facilities, nonetheless impact the identification and selection of regional transmission facilities. See also *Duke Energy Carolinas, LLC*, 186 FERC ¶ 61,178, at PP 13, 27 (2024) (accepting Duke’s OATT revisions to adopt a stakeholder meeting process that includes an Assumptions Meeting, Needs Meeting, and Solutions Meeting, each no fewer than 25 calendar days apart).

³⁵⁰⁰ Dominion Initial Comments at 68; Eversource Initial Comments at 47–48; NESCOE Initial Comments at 78; Xcel Initial Comments at 17.

³⁵⁰¹ Indicated PJM TOs Initial Comments at 42.

³⁵⁰² MISO Initial Comments at 84.

stakeholder meetings a minimum of 25 calendar days apart and prescribing the type of information that transmission providers must share at each meeting is necessary to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential. We balance the increased burden imposed on transmission providers with the benefits associated with providing increased information and opportunities for stakeholder review of and comment on the local transmission planning inputs that are used in the regional transmission planning process. In addition, as discussed above, we believe that these reforms will reduce after-the-fact disputes and will help facilitate the identification of regional transmission facilities that may be more efficient or cost-effective than proposed local transmission facilities. As a result, the incremental burden of having to hold three stakeholder meetings to share this information and to consider input from stakeholders in response to this information is outweighed by the benefits that the increased transparency will provide.

1642. We also find unconvincing Eversource's assertion that the reforms will not work where there is not a precisely defined regional transmission planning cycle, such as is the case in ISO-NE.³⁵⁰³ The requirement to hold three publicly-noticed stakeholder meetings is triggered by the submission of local transmission planning information to the transmission planning region for inclusion in the regional transmission planning process and is not tied to a particular transmission planning cycle. Nevertheless, we recognize that these reforms may require transmission providers to propose adjustments to their existing processes. But as explained above, we believe that the need for transparency and stakeholder involvement requires these changes to ensure that Commission-jurisdictional rates are just and reasonable and not unduly discriminatory or preferential.

1643. In response to TAPS' request that transmission providers be required to post their transmission planning criteria, models, and assumptions,³⁵⁰⁴ we reiterate that transmission providers must provide this information as part of the Assumptions Meeting. We further note that the requirement for transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission systems

is an existing requirement of Order No. 890. This information must enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion.³⁵⁰⁵ The Commission recognized in Order No. 890 that safeguards must be put in place to ensure that confidentiality and CEII concerns are adequately addressed in transmission planning activities and, therefore, requires that transmission providers have mechanisms in place in their OATTs to manage confidentiality and CEII concerns, such as confidentiality agreements and password-protected access to information.³⁵⁰⁶ However, we reiterate that information must be disclosed, under applicable confidentiality provisions, if the information is needed to participate in the transmission planning process and to replicate transmission planning studies, which necessarily includes access to the models that underlie transmission planning processes.

1644. We decline to require, as requested by American Municipal Power and TAPS, that transmission providers hold two Solutions Meetings.³⁵⁰⁷ While a transmission provider may determine that additional stakeholder meetings are appropriate or necessary, we only require transmission providers to conduct the three publicly-noticed stakeholder meetings discussed above. However, there is nothing in this final order that prohibits transmission providers from holding additional meetings, beyond those required here. We find NRG's request that the Commission require the local transmission planning process include an estimated rate impact for each year if the local transmission plan were to be executed to be beyond the scope of the proposal, although transmission providers may choose to provide this information outside of the context of this order.

1645. In response to commenters that request that the Commission require transmission providers to respond to all comments and questions submitted by stakeholders in the local transmission planning process,³⁵⁰⁸ we clarify that

such a requirement could be too prescriptive in certain circumstances and thus we decline to set a bright-line rule that transmission providers must respond to each and every question or comment received through the stakeholder process. Nevertheless, we require transmission providers to respond to questions or comments in a manner that allows stakeholders to meaningfully participate in these stakeholder meetings. For example, in the context of live discussions in any of the three required publicly-noticed stakeholder meetings, we expect transmission providers to offer stakeholders an opportunity to speak, engage, and ask questions, as well as receive reasonable responses at the meeting consistent with meaningful participation. Overall, we encourage transmission providers to be as responsive as possible to stakeholder comments and questions. However, we recognize that not all comments or questions require an answer or a response, or that some responses may be unduly burdensome to the transmission provider. To the extent that there are disagreements, we note that stakeholders have dispute resolution procedures available, as required under Order No. 890.³⁵⁰⁹ Some commenters have asked the Commission to require transmission providers to provide "additional clarity" regarding how alternatives were developed and why they were not selected during the Solutions Meeting, as requested by American Municipal Power.³⁵¹⁰ In balancing the need for transparency and the burden for transmission providers, we find that a meaningful participation standard regarding sharing of local transmission planning inputs that are used in the regional transmission planning process that are established by the Commission is reasonable.

1646. In addition, in response to TAPS' request regarding disputes over local transmission planning inputs,³⁵¹¹ we clarify that where disputes arise regarding transparency into the local transmission planning inputs, the transmission provider's existing dispute resolution process, as established in Order No. 890, governing the transmission planning process should be used.³⁵¹² Further, affected entities

³⁵⁰⁵ Order No. 890, 118 FERC ¶ 61,119 at P 471.

³⁵⁰⁶ *Id.* P 460.

³⁵⁰⁷ American Municipal Power Initial Comments at 24–25; TAPS Initial Comments at 62 (citing NOPR, 179 FERC ¶ 61,028 at P 402).

³⁵⁰⁸ See American Municipal Power Initial Comments at 18–19; California Commission Initial Comments at 112–113; DC and MD Offices of People's Counsel Initial Comments at 6; Kentucky

Commission Chair Chandler Initial Comments at 21–22; Northwest and Intermountain Initial Comments at 20–21; TAPS Initial Comments at 62.

³⁵⁰⁹ Order No. 890, 118 FERC ¶ 61,119 at PP 501–503.

³⁵¹⁰ American Municipal Power Initial Comments at 24–25.

³⁵¹¹ TAPS Initial Comments at 62 (citing Order No. 890, 118 FERC ¶ 61,119 at PP 501–503).

³⁵¹² Order No. 890, 118 FERC ¶ 61,119 at P 501.

³⁵⁰³ Eversource Initial Comments at 47.

³⁵⁰⁴ TAPS Initial Comments at 61.

retain any rights that they may have under FPA section 206 to file complaints with the Commission.

b. Additional Issues

1647. As it pertains to PPL's request that the Commission clarify that confidential or sensitive information will be protected,³⁵¹³ we clarify that transmission providers must continue to apply the same safeguards to protect sensitive or critical information, such as confidentiality agreements and password protected access to information, as the Commission required in Order No. 890 and that transmission providers currently apply to the sharing of transmission planning information to protect against inappropriate disclosure of confidential information.³⁵¹⁴

1648. Many commenters suggest additional reforms because these commenters find the NOPR proposal insufficient. These suggested reforms include additional measures to protect customers' interests and additional process, more oversight, more monitoring (including establishing an independent transmission monitor), or prudence reviews;³⁵¹⁵ requiring RTOs/ISOs to assume a larger role in reviewing or approving identified local transmission projects;³⁵¹⁶ requiring a performance-based method of enhancing transparency in local transmission planning processes;³⁵¹⁷ and requiring transmission providers to make available additional transmission planning data,³⁵¹⁸ improve formatting of transmission planning inputs,³⁵¹⁹ or otherwise coordinate with load-serving entities to transfer data and information.³⁵²⁰ The Commission did

not make such proposals in the NOPR and, as a result, we find these requests to be beyond the scope of this proceeding and decline to adopt them. We note, however, that several of these issues may be examined in the Commission's ongoing Transmission Planning and Cost Management proceeding.³⁵²¹

C. Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

1. Eligibility

a. NOPR Proposal

1649. The Commission proposed to require, as part of each Long-Term Regional Transmission Planning cycle, transmission providers in each transmission planning region to evaluate whether transmission facilities operating at or above 230 kV that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be "right-sized" to more efficiently or cost-effectively address regional transmission needs identified in Long-Term Regional Transmission Planning. The Commission proposed to define "right-sizing" as the process of modifying a transmission provider's in-kind replacement of an existing transmission facility to increase that facility's transfer capability.³⁵²²

1650. The Commission described the process under this proposed reform as entailing the following steps. First, sufficiently early in each Long-Term Regional Transmission Planning cycle, each transmission provider would submit its in-kind replacement estimates for use in Long-Term Regional Transmission Planning. Then, if a right-sized replacement transmission facility is identified as a potential solution to a Long-Term Regional Transmission Planning need, that right-sized replacement transmission facility would be evaluated in the same manner as any other proposed transmission facility to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need. If a right-sized replacement transmission facility addresses the transmission provider's need to replace an existing transmission facility, meets all of the applicable selection criteria included in Long-Term Regional Transmission Planning, and is found to be the more efficient or cost-effective

solution to a transmission need identified through Long-Term Regional Transmission Planning, then the right-sized replacement transmission facility may be selected in the regional transmission plan for purposes of cost allocation.³⁵²³

1651. The Commission explained that nothing in the reforms proposed in the NOPR would alter a transmission provider's existing rights and responsibilities under existing laws with respect to maintaining, and when necessary, replacing, existing transmission facilities. Further, as the Commission explained, it may be possible for an in-kind replacement transmission facility to be *included* in the regional transmission plan for informational purposes, but not be *selected*.³⁵²⁴

b. Comments

1652. Several commenters support the NOPR's proposals related to right-sizing.³⁵²⁵ ITC states that the NOPR proposal will result in better use of existing facilities and rights-of-way to quickly deliver additional transmission capacity. ITC maintains that increasing the transfer capability of existing transmission facilities lessens the impacts on communities and other land users, in addition to raising fewer environmental considerations.³⁵²⁶ ITC adds that right-sizing will form a critical input to transmission planning and state siting processes by encouraging designs that meet future needs.³⁵²⁷

1653. OMS also supports the Commission's proposed realignment of incentives to ensure that transmission providers are not incentivized through right-sizing to rebuild and replace facilities before considering other opportunities, instead providing a level playing field to consider other solutions.³⁵²⁸ PJM states that right-sizing allows transmission owners to meet their reliability obligations while transmission providers have the opportunity to find more efficient

³⁵¹³ PPL Initial Comments at 36.

³⁵¹⁴ Order No. 890, 118 FERC ¶ 61,119 at PP 460, 471.

³⁵¹⁵ California Commission Initial Comments at 111–112 &n.401; Colorado Consumer Advocates Initial Comments at 31; Joint Consumer Advocates Initial Comments at 25–29; NRG Initial Comments at 7, 36; Ohio Consumers Initial Comments at 23–24; OMS Initial Comments at 16–17; Pattern Energy Initial Comments at 31–34; Pine Gate Initial Comments at 49–50; PIOs Initial Comments at 51–52; PJM States Initial Comments at 4–6; TAPS Initial Comments at 61–62; US DOJ and FTC Initial Comments at 20–21.

³⁵¹⁶ See American Municipal Power Reply Comments at 3–7; California Commission Initial Comments at 108–110; DC and MD Offices of People's Counsel Initial Comments at 7; NARUC Initial Comments at 60–61; Ohio Consumers Reply Comments at 17–18; PJM States Initial Comments at 6–7.

³⁵¹⁷ Vermont Electric and Vermont Transco Initial Comments at 5.

³⁵¹⁸ American Municipal Power Initial Comments at 21–24 (citations omitted); Pattern Energy Initial Comments at 30–34.

³⁵¹⁹ Joint Consumer Advocates Initial Comments at 21–22.

³⁵²⁰ Certain TDUs Initial Comments at 18.

³⁵²¹ Transmission Planning and Cost Management, Notice of Technical Conference, Docket No. AD22–8–000 (Apr. 21, 2022).

³⁵²² NOPR, 179 FERC ¶ 61,028 at P 403.

³⁵²³ *Id.* P 407.

³⁵²⁴ *Id.* PP 412–413.

³⁵²⁵ ACORE Initial Comments at 19; Ameren Initial Comments at 46–47; APPA Initial Comments at 48; California Energy Commission Initial Comments at 3; CTC Global Initial Comments at 18; ELCON Initial Comments at 27; Evergreen Action Initial Comments at 4; ITC Initial Comments at 45; ITC Reply Comments at 29; New York Commission and NYSEDA Initial Comments at 15; Northwest and Intermountain Initial Comments at 21; OMS Initial Comments at 17; PJM Initial Comments at 9, 121–122; SEIA Initial Comments at 26; U.S. Chamber of Commerce Initial Comments at 11; Vermont Electric and Vermont Transco Initial Comments at 5.

³⁵²⁶ ITC Initial Comments at 45.

³⁵²⁷ ITC Reply Comments at 29.

³⁵²⁸ OMS Initial Comments at 17.

solutions to regional transmission needs and avoid duplicative transmission development.³⁵²⁹

1654. AEP supports applying the right-sizing evaluation to transmission facilities operating at or above 230 kV because replacement transmission facilities that will operate at or above 230 kV are most susceptible to modification to meet long-term regional transmission needs.³⁵³⁰ PG&E also supports the proposed voltage threshold, claiming that the inclusion of lower voltage transmission projects would substantially expand the number of projects that would need to be evaluated for right-sizing while offering little benefit. Specifically, PG&E contends that lower voltage transmission projects are typically needed for specific, local purposes and thus do not need to be right-sized, and that a requirement that they be evaluated for right-sizing would burden the RTO/ISO process.³⁵³¹

1655. APPA supports the NOPR proposal's use of a 10-year timeframe for the right-sizing reform.³⁵³² AEP also supports a 10-year horizon for identifying in-kind replacements, so long as the list of transmission facilities is non-binding and may be modified as transmission projects mature or expected facility lives can be extended through other means.³⁵³³

1656. CAISO requests that the Commission clarify that the NOPR does not preclude it from continuing to consider modifications to in-kind replacements for transmission facilities below 230 kV in its annual transmission planning process.³⁵³⁴

1657. Several commenters support the NOPR's right-sizing proposal but with certain conditions.³⁵³⁵ Further, some

commenters argue that if the Commission adopts the NOPR proposal, the Commission must ensure that the proposal does not disrupt or impair existing local transmission planning processes.³⁵³⁶ For example, AEP asserts that the Commission must ensure that the NOPR proposal does not undermine the local transmission planning process or transmission owners' rights to build transmission projects that address local needs.³⁵³⁷ Mississippi Commission asserts that, if the NOPR proposal is adopted, the ultimate decision as to which local transmission project is constructed must rest with the states that have transmission siting authority and the incumbent transmission owners.³⁵³⁸ PJM States ask for clarification on how the NOPR proposal will interact with existing processes, noting that in PJM, any need that appears both on a five-year end-of-life needs list and in PJM's regional transmission plan is eligible for competition (as compared to the NOPR proposal, under which transmission projects to address 10-year-out needs would not be eligible for competition).³⁵³⁹

1658. NESCOE states that ISO-NE lacks the clear standards required to support right-sizing, citing an Eversource transmission project that improved grid reliability but was ineligible for regional cost allocation because it did not meet the standards to qualify as a right-sized project.³⁵⁴⁰ NESCOE argues that more transparency into the right-sizing processes is necessary to ensure that the results are disciplined, cost-conscious investments.³⁵⁴¹

1659. Several commenters oppose the NOPR's right-sizing proposal.³⁵⁴²

Competition Coalition asserts that the NOPR proposal would result in overbuilding the transmission system now for speculative future transmission needs, leaving customers with the bill for any stranded costs.³⁵⁴³ Louisiana Commission claims that the NOPR right-sizing proposal should not be adopted because it will intrude on its retail authority.³⁵⁴⁴

1660. Other commenters argue that the proposed 230 kV threshold is inappropriate.³⁵⁴⁵ For example, Avangrid contends that it is overly prescriptive and does not reflect regional conditions, needs, and stakeholder interests.³⁵⁴⁶ Avangrid states that, in ISO-NE, a 230 kV threshold would result in in-kind replacement of lower voltage transmission facilities rather than right-sizing facilities to most efficiently meet transmission needs identified through Long-Term Regional Transmission Planning.

1661. Kentucky Commission Chair Chandler argues that 200 kV or 230 kV are no longer adequate rules of thumb to delineate local versus regional transmission facilities, as transmission facilities that may have been formerly classified as local are likely to be regional in the future. Rather, Kentucky Commission Chair Chandler states that transmission facilities rated between 100 kV and 200 kV will play a greater role in the regional delivery of energy.³⁵⁴⁷ Ohio Consumers argue that the Commission should lower the threshold to 69 kV because many end-of-life transmission facilities in the PJM transmission planning process are expensive rebuilds of transmission facilities that are rated below 230 kV.³⁵⁴⁸ TAPS argues that excluding lower voltage facilities prevents transmission planning regions from being able to consider more efficient and cost-effective alternatives.³⁵⁴⁹

1662. LS Power asserts that the Commission should not limit its right-sizing proposal to facilities above 230 kV and that such reforms should apply

³⁵²⁹ PJM Initial Comments at 121–122 (citing NOPR, 179 FERC ¶ 61,028 at PP 406, 408).

³⁵³⁰ AEP Initial Comments at 44–45 (citing NOPR, 179 FERC ¶ 61,028 at P 406).

³⁵³¹ PG&E Reply Comments at 14–15.

³⁵³² APPA Initial Comments at 48 (citing NOPR, 179 FERC ¶ 61,028 at P 403).

³⁵³³ AEP Initial Comments at 44–45.

³⁵³⁴ CAISO Initial Comments at 50.

³⁵³⁵ ACEG Initial Comments at 8–9, 56–58; AEP Initial Comments at 43–44; Avangrid Initial Comments at 15–16; Breakthrough Energy Initial Comments at 3, 19; California Commission Initial Comments at 113–118; California Water Initial Comments at 8–9; Clean Energy Associations Initial Comments at 36–37; EEI Initial Comments at 41; Eversource Initial Comments at 52; Exelon Initial Comments at 3, 51; ISO-NE Initial Comments at 39; MISO Initial Comments at 87; NARUC Initial Comments at 58–59, 63–64; NESCOE Initial Comments at 21–22, 78–79; NESCOE Reply Comments at 6–8; NESCOE Supplemental Comments at 7–9; NextEra Initial Comments at 66–67; NRECA Initial Comments at 67; NYISO Initial Comments at 58–60; PG&E Initial Comments at 12–14; Pine Gate Initial Comments at 46–50; PIOs Initial Comments at 57–58; State Agencies Initial

Comments at 20–22; TAPS Initial Comments at 6–7, 64; VEIR Initial Comments at 6; Vermont State Entities Initial Comments at 11–13; WIRES Initial Comments at 10.

³⁵³⁶ See AEP Initial Comments at 43–44; CAISO Initial Comments at 50; Mississippi Commission Initial Comments at 30–31; Mississippi Commission Reply Comments at 9–10; PJM States Initial Comments at 8; WIRES Initial Comments at 10.

³⁵³⁷ AEP Initial Comments at 43–44.

³⁵³⁸ Mississippi Commission Initial Comments at 30–31.

³⁵³⁹ PJM States Initial Comments at 8 (citing PJM, Intra-PJM Tariffs, OATT, attach. M–3 (1.0.0), section (d)1.iii).

³⁵⁴⁰ NESCOE Reply Comments at 6–8.

³⁵⁴¹ NESCO Supplemental Comments at 9.

³⁵⁴² Anbaric Initial Comments at 7; Competition Coalition Initial Comments at 62–63; DC and MD Offices of People's Counsel Initial Comments at 47–48; Idaho Power Initial Comments at 13; Kentucky Commission Chair Chandler Initial Comments at 16–19; Louisiana Commission Initial Comments at 39; LS Power Initial Comments at 135–136, 138, 141–142, 145–146; Massachusetts Attorney General Initial Comments at 51–52; Ohio Consumers Initial Comments at 23; Resale Iowa Initial Comments at 8–9.

³⁵⁴³ Competition Coalition Initial Comments at 62–63.

³⁵⁴⁴ Louisiana Commission Initial Comments at 39.

³⁵⁴⁵ Avangrid Initial Comments at 15–16; California Commission Initial Comments at 117–118; Kentucky Commission Chair Chandler Initial Comments at 18–19; New York TOs Initial Comments at 17–18; NYISO Initial Comments at 59; Ohio Consumers Initial Comments at 23; PJM Initial Comments at 9, 121–122; State Agencies Initial Comments at 20–21; TAPS Initial Comments at 6, 66.

³⁵⁴⁶ Avangrid Initial Comments at 15–16.

³⁵⁴⁷ Kentucky Commission Chair Chandler Initial Comments at 18–19.

³⁵⁴⁸ Ohio Consumers Initial Comments at 23.

³⁵⁴⁹ TAPS Initial Comments at 6, 66.

to lower voltage transmission facilities as well.³⁵⁵⁰ Specifically, LS Power argues that transmission facilities that operate at or above 100 kV (and sometimes facilities operating at a lower voltage) are regional in nature and should be subject to exclusively regional transmission planning.³⁵⁵¹

1663. Shell states that the Commission should consider lowering the proposed voltage threshold to 115 kV, but notes that doing so may include lower voltage facilities that predominantly serve sub-transmission, wholesale distribution, or retail distribution purposes and have only local benefits.³⁵⁵² To ensure that the costs of sub-transmission, wholesale distribution, or retail distribution facilities are not rolled into transmission rates, Shell argues that the Commission should reexamine its standards for rolling the costs of transmission facilities into rates, its application of the Seven Factor test for functionalizing facilities as distribution or transmission, and its *Mansfield* integration analysis.³⁵⁵³ Western Utilities contend that the Commission should not adopt Shell's proposal to lower the right-sizing threshold to 115 kV because whether or not a facility is a transmission facility is a fact-specific question.³⁵⁵⁴

1664. Pine Gate recommends against the Commission adopting the bright-line voltage threshold specified in the NOPR, but urges the Commission require each transmission provider to: (1) list and evaluate existing transmission facilities operating at or above 230 kV that it owns and estimates may need to be replaced with a new in-kind transmission facility over the next 10 years; and (2) establish criteria by which it will identify lower-voltage facilities that could potentially be right-sized through Long-Term Regional Transmission Planning.³⁵⁵⁵ Relatedly,

WIRES states that the Commission should either: (1) clarify that transmission providers would not be prohibited from considering right-sizing transmission facilities at a lower voltage threshold if existing transmission planning processes already do so; or (2) provide flexibility for transmission planning regions to justify the use of a different voltage threshold.³⁵⁵⁶

1665. Some commenters oppose the NOPR proposal's use of a 10-year timeframe for the right-sizing reform.³⁵⁵⁷ Exelon states that the Commission's proposed requirement to have a 10-year time horizon for identifying a list of potential end-of-useful life needs is infeasible and inconsistent with utility practices. Specifically, Exelon states that it does not develop a concrete plan for transmission projects to meet end-of-useful life needs five years in advance—let alone 10 years—but instead maintains a “dynamic list” of older assets, the condition of which is evaluated on a rolling basis, based on numerous factors such as equipment inspection and testing, maintenance history, historical performance, obsolescence, operational experience, asset criticality, equipment failure data, and age.³⁵⁵⁸

1666. Some commenters argue that the NOPR proposal is not applicable to their transmission planning regions or that their existing processes are sufficient.³⁵⁵⁹ For example, CAISO explains that it plans all upgrades and expansions of transmission facilities under its operational control, which include transmission facilities at all voltage levels and at all locations on the system. Further, CAISO states that, if an asset management, maintenance, or in-kind replacement project can be expanded or modified to address a CAISO-identified transmission need in a local area (or system wide), CAISO can order such expansion or modification in

its regional transmission planning process.³⁵⁶⁰

1667. MISO asserts that right-sizing is fundamental to transmission planning and should always be considered as part of Good Utility Practice, but that right-sizing decisions are best made on a case-by-case basis, as there are both quantitative and qualitative considerations that must be taken into account.³⁵⁶¹ MISO contends that its existing local transmission planning achieves the Commission's objectives, as the MISO process provides for right-sizing where MISO selects the most robust solution. Accordingly, MISO states that, for its footprint, no changes are needed.³⁵⁶²

1668. SERTP Sponsors argue that replacement decisions for particular equipment may be triggered more by the conditions of a particular facility than its age. SERTP Sponsors argue that a process like right-sizing already occurs in SERTP's regional transmission planning, which requires that the SERTP Sponsors affirmatively look to determine if there are regional transmission alternatives that would be more efficient or cost-effective than the transmission solutions otherwise included in SERTP's regional transmission plan, including projects to replace aging infrastructure.³⁵⁶³

1669. Several commenters argue that the Commission should adopt alternative or additional requirements that apply when transmission providers evaluate transmission facilities for right-sizing.³⁵⁶⁴ For example, Ameren requests that the Commission require transmission providers to consider the following additional criteria when determining whether a transmission facility is eligible for right-sizing: (1) whether a transmission line is in the top 10 limiting elements on an import or transfer study; (2) whether a line has shown up as a real-time binding

³⁵⁵⁰ See LS Power Partial Reply Comments at 61–64 (citing California Commission Initial Comments at 117; Eversource Initial Comments at 38; ISO-NE Initial Comments at 39; Kentucky Commission Chair Chandler Initial Comments at 19; LS Power Initial Comments at 142; NARUC Initial Comments at 64; Ohio Consumers Initial Comments at 23; State Agencies Initial Comments at 21).

³⁵⁵¹ *Id.* at 64.

³⁵⁵² Shell Reply Comments at 10 (citing Shell Initial Comments at 34).

³⁵⁵³ Shell Initial Comments at 34–36; Shell Reply Comments at 10–11 (citing *Commonwealth Edison Co.*, 167 FERC ¶ 61,173, at P 12 n.23 (2019); *Buckeye Power, Inc. v. Am. Transmission Sys. Inc.*, Opinion No. 533, 148 FERC ¶ 61,174, at PP 12, 41, 69 (2014), *order on reh'g*, 151 FERC ¶ 61,091 (2015); *Mansfield Mun. Elec. Dep't v. New England Power Co.*, Opinion No. 454, 97 FERC ¶ 61,134 (2001), *order on reh'g*, Opinion No. 454–A, 98 FERC ¶ 61,115 (2002)).

³⁵⁵⁴ See Western Utilities Reply Comments at 2 (citing Shell Initial Comments at 34–35).

³⁵⁵⁵ Pine Gate Initial Comments at 48.

³⁵⁵⁶ WIRES Initial Comments at 10.

³⁵⁵⁷ Eversource Initial Comments at 53; Exelon Initial Comments at 54–55; Indicated PJM TOs Initial Comments at 46–47; Kentucky Commission Chair Chandler Initial Comments at 17–18; SERTP Sponsors Initial Comments at 38–39.

³⁵⁵⁸ Exelon Initial Comments at 54–55 (*Exelon Utilities Asset Management Guidelines and Practices* 3 (Nov. 18, 2020), <https://pjm.com/-/media/committees-groups/committees/srtepm-2020/20201216/20201216-exelon-final-end-eol-guidelines.ashx>).

³⁵⁵⁹ CAISO Initial Comments at 47–48; Dominion Initial Comments at 69–70, 72; Duke Initial Comments at 46; MISO Initial Comments at 87–88; MISO Reply Comments at 28; New York TOs Initial Comments at 17; SERTP Sponsors Initial Comments at 38–39; SPP Initial Comments at 34–35.

³⁵⁶⁰ CAISO Initial Comments at 47–48 (citing CAISO ANOPR Initial Comments at 73; *Cal. Pub. Utils. Comm'n v. Pac. Gas and Elec. Co.*, 164 FERC ¶ 61,161 at PP 35–37, 69).

³⁵⁶¹ MISO Initial Comments at 87.

³⁵⁶² MISO Reply Comments at 28 (citing OMS Initial Comments at 15–17).

³⁵⁶³ SERTP Sponsors Initial Comments at 38–39 (citations omitted).

³⁵⁶⁴ ACEG Initial Comments at 58; Ameren Initial Comments at 46–47; American Municipal Power Initial Comments at 27; Breakthrough Energy Initial Comments at 18–19; California Energy Commission Initial Comments at 3; Competition Coalition Initial Comments at 68; CTC Global Initial Comments at 18; Eversource Initial Comments at 53; Exelon Initial Comments at 56–58; Grid United Initial Comments at 3–4; Pennsylvania Commission Initial Comments at 21; PG&E Initial Comments at 13–14; Pine Gate Initial Comments at 48; PIOs Initial Comments at 57–58; PJM Initial Comments at 9, 121–122; PPL Initial Comments at 36–37; Shell Initial Comments at 34.

constraint in the last two years; or (3) whether a line shows up as a binding constraint in future security constrained economic dispatch simulations.³⁵⁶⁵ California Energy Commission argues that the Commission should develop a definition of “right-sizing,” possibly tied to a specified planning reserve margin as well as an expected level of demand growth.³⁵⁶⁶ Furthermore, ACEG and PG&E both request that the Commission consider the use of existing transmission facility rights-of-way as an eligibility threshold for potentially right-sized replacement transmission facilities.³⁵⁶⁷

1670. Eversource asserts that it would be more efficient to evaluate potential right-sizing: (1) through a review of the transmission facilities that could be upgraded to address identified long-term transmission needs, including an evaluation of whether an in-kind replacement is likely to occur during the planning horizon; or (2) through transmission owner identification of right-sizing options that align with needs identified in the longer-term study as they perform their normal asset condition projects.³⁵⁶⁸

1671. Entergy asserts that the Commission should clarify that storm-hardening transmission projects are not subject to a right-sizing requirement because it would add complications and delays to the right-sizing process.³⁵⁶⁹ Pennsylvania Commission argues that a transmission facility should not be right-sized if its total cost exceeds the total cost of the local transmission project and a competitively procured transmission project to address the regional need.³⁵⁷⁰

1672. Some commenters call for the Commission to expand the right-sizing reform to other categories of transmission facilities.³⁵⁷¹ Eversource argues that the Commission should encourage transmission providers to incorporate right-sizing considerations into other transmission planning processes, such as the reliability planning process, as appropriate.³⁵⁷²

Similarly, ACORE and American Municipal Power request that the Commission clarify that right-sizing also applies in any short-term transmission planning for reliability and economic transmission projects.³⁵⁷³ Grid United states that the Commission should require Long-Term Regional Transmission Planning to assess and allow for up-sizing transmission projects, such as building a single circuit transmission line that is double-circuit ready.³⁵⁷⁴

1673. Several commenters argue that the Commission should allow flexibility on the thresholds for evaluating transmission facilities for right-sizing.³⁵⁷⁵ To prevent needless litigation that will cause delays and cost increases for customers, Dominion states that any final order should be clear that transmission providers will not be penalized if a replacement project arises that was not previously identified.³⁵⁷⁶

1674. NYISO contends that the final order should permit transmission providers, with input from state entities and stakeholders, to integrate planning for right-sizing transmission replacements into existing transmission planning processes, including by considering transmission facilities that they anticipate will be replaced in-kind when identifying transmission needs in short-term or long-term transmission planning.³⁵⁷⁷

1675. US DOE encourages the Commission to provide sufficient flexibility to ensure that the proposed reforms are cost-effective and do not overburden the transmission planning process. US DOE asserts that transmission providers should not be required to submit every in-kind replacement for all equipment above 230 kV for consideration for right-sizing and that regional transmission planning processes should not be required to consider each piece of equipment

provided by each member of a transmission planning region.³⁵⁷⁸

1676. PG&E argues that the Commission should allow for flexibility in any right-sizing-related requirements, noting that a transmission provider may need to replace an aging or failing transmission facility sooner than a right-sized transmission project can be developed. In that case, PG&E states that the transmission owner would need to proceed with the replacement project to ensure reliability or protect public safety even if the RTO/ISO had determined that a transmission facility would benefit from being right-sized.³⁵⁷⁹

c. Commission Determination

1677. We adopt the NOPR proposal, with modification, to require that, as part of each Long-Term Regional Transmission Planning cycle, transmission providers in each transmission planning region evaluate whether transmission facilities (1) operating above a specified kV threshold and (2) that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be “right-sized” to more efficiently or cost-effectively address a Long-Term Transmission Need. To effectuate this reform, we also adopt the NOPR proposal, with modification, to require that, sufficiently early in each Long-Term Regional Transmission Planning cycle, each transmission provider submit its in-kind replacement estimates (*i.e.*, estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years) for use in Long-Term Regional Transmission Planning. With respect to the specified kV threshold, transmission providers must propose on compliance a threshold that does not exceed 200 kV (*e.g.*, 115 kV and above). In adopting the right-sizing reform in this final order, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing existing transmission facilities. We also adopt the NOPR proposals regarding a Federal right of first refusal and cost allocation method for right-sized replacement transmission facilities, as discussed below.

³⁵⁷³ ACORE Initial Comments at 19; American Municipal Power Initial Comments at 27.

³⁵⁷⁴ Grid United Initial Comments at 4.

³⁵⁷⁵ American Municipal Power Initial Comments at 27; APPA Initial Comments at 48; Avangrid Initial Comments at 15–16; California Commission Initial Comments at 117; Clean Energy Associations Initial Comments at 36–37; Dominion Initial Comments at 72–73; EEL Initial Comments at 41; Eversource Initial Comments at 52–53; ISO–NE Initial Comments at 39; NARUC Initial Comments at 58–59, 63–64; National Grid Initial Comments at 40–41; NESCOE Initial Comments at 80; New York TOs Initial Comments at 18; NRECA Initial Comments at 67; NYISO Initial Comments at 9, 60; PG&E Reply Comments at 14–15; PPL Initial Comments at 37; US DOE Initial Comments at 48; Vermont State Entities Initial Comments at 13; WIRES Initial Comments at 10.

³⁵⁷⁶ Dominion Initial Comments at 73.

³⁵⁷⁷ NYISO Initial Comments at 9, 60.

³⁵⁷⁸ US DOE Initial Comments at 48.

³⁵⁷⁹ PG&E Reply Comments at 15.

³⁵⁶⁵ Ameren Initial Comments at 46–47.

³⁵⁶⁶ California Energy Commission Initial Comments at 3.

³⁵⁶⁷ ACEG Initial Comments at 57–58; PG&E Initial Comments at 13.

³⁵⁶⁸ Eversource Initial Comments at 53.

³⁵⁶⁹ Entergy Initial Comments at 38.

³⁵⁷⁰ Pennsylvania Commission Initial Comments at 21.

³⁵⁷¹ American Municipal Power Initial Comments at 27; Avangrid Initial Comments at 16; Clean Energy Associations Initial Comments at 26–27, 37; Eversource Initial Comments at 54; MISO Initial Comments at 88; NYISO Initial Comments at 59–60; PIOs Initial Comments at 57–58; TAPS Initial Comments at 6, 64–65.

³⁵⁷² Eversource Initial Comments at 54.

1678. We adopt the NOPR proposal to define “right-sizing” as the process of modifying a transmission provider’s in-kind replacement of an existing transmission facility to increase that facility’s transfer capability.³⁵⁸⁰ Additionally, we clarify that, for purposes of this right-sizing reform, an “in-kind replacement transmission facility” is a new transmission facility that: (1) would replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as needing to be replaced; (2) would result in no more than an incidental increase in capacity over the existing transmission facility identified as needing to be replaced;³⁵⁸¹ and (3) is located in the same general route as, and/or uses the existing rights-of-way of, the existing transmission facility identified as needing to be replaced.

1679. Further, we clarify that a “right-sized replacement transmission facility” is a new transmission facility that: (1) would meet the need to replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as one that it plans to replace with an in-kind replacement transmission facility while also addressing a Long-Term Transmission Need; (2) results in more than an incidental increase in the capacity of an existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate; and (3) is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate. We believe these clarifications are necessary to ensure that use of the right-sizing reform addresses replacement transmission facilities and not entirely new transmission facilities.

1680. As an example, assume that transmission providers determine that an existing transmission facility included in a transmission provider’s

in-kind replacement estimate can be right-sized (Segment 1) and, together with a separate new transmission facility (Segment 2), is the more efficient or cost-effective solution to a Long-Term Transmission Need. In this example, Segment 1 is a new 50-mile, 345 kV transmission facility between interconnection points A and B that requires the expansion of an existing right-of-way, and replaces an existing 50-mile, 230 kV transmission facility between interconnection points A and B. Segment 2 in this example is a new 25-mile, 345 kV transmission facility requiring entirely new rights-of-way from interconnection points B to C. If both Segment 1 and Segment 2 are selected to address a Long-Term Transmission Need, then, for purposes of the requirements of this final order, only Segment 1 would be considered a right-sized replacement transmission facility.

1681. Consistent with the NOPR proposal, and as discussed further below, the process under this proposed right-sizing reform entails taking the following steps, which transmission providers must describe in their OATTs. The transmission providers in each transmission planning region must propose a point sufficiently early in each Long-Term Regional Transmission Planning cycle at which each individual transmission provider in the transmission planning region will submit its in-kind replacement estimates for use in Long-Term Regional Transmission Planning. Then, if transmission providers identify a right-sized replacement transmission facility as a potential solution to a Long-Term Transmission Need as part of Long-Term Regional Transmission Planning, that right-sized replacement transmission facility must be evaluated in the same manner as any other proposed Long-Term Regional Transmission Facility to determine whether it is the more efficient or cost-effective transmission facility to address the transmission need. More specifically, it is at this stage of the right-sizing reform where transmission providers must use the in-kind replacement estimates to determine if in-kind replacement transmission facilities could be right-sized to more efficiently or cost-effectively address a Long-Term Transmission Need(s). If a right-sized replacement transmission facility addresses the transmission provider’s need to replace an existing transmission facility, meets the applicable selection criteria included in Long-Term Regional Transmission Planning, and is found to be the more

efficient or cost-effective solution to a Long-Term Transmission Need, then the right-sized replacement transmission facility must be considered for selection.

1682. We find that a right-sized replacement transmission facility has the potential to both meet an individual transmission provider’s responsibility to maintain the reliability of its existing transmission system and address a Long-Term Transmission Need more efficiently or cost-effectively than an in-kind replacement transmission facility or another Long-Term Regional Transmission Facility.³⁵⁸² Further, we find that, if opportunities for right-sized replacement transmission facilities are not considered, the Long-Term Regional Transmission Planning process may not select the more efficient or cost-effective transmission facilities to meet Long-Term Transmission Needs, potentially rendering Commission-jurisdictional rates unjust and unreasonable.³⁵⁸³

1683. As noted above, for purposes of implementing the right-sizing requirements that we adopt in this final order, transmission providers must propose on compliance a threshold that does not exceed 200 kV that is used in identifying the transmission facilities that an individual transmission provider anticipates replacing in-kind with a new transmission facility during the next 10 years, which it must then include in its in-kind replacement estimates. In other words, each transmission provider in the transmission planning region must include in its in-kind replacement estimates the transmission facilities operating at and above 200 kV, or at and above a lower proposed threshold, that it owns and anticipates replacing in-kind with a new transmission facility during the next 10 years.³⁵⁸⁴ We find that this threshold strikes a reasonable balance between capturing the transmission facilities that are the most likely candidates for right-sizing without overburdening transmission providers by requiring them to identify all transmission facilities planned for in-kind replacement, including lower voltage transmission facilities that may be less likely to provide regional benefits, and therefore potentially less likely to be more efficient or cost-effective transmission solutions to Long-

³⁵⁸⁰ NOPR, 179 FERC ¶ 61,028 at P 403 (“Right-sizing could include, for example, increasing the transmission facility’s voltage level, adding circuits to the towers (e.g., redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (such as advanced conductor technologies).”).

³⁵⁸¹ The Commission has addressed the meaning of an incidental increase in the context of a replacement transmission facility in several orders. See, e.g., *S. Cal. Edison Co.*, 164 FERC ¶ 61,160 at P 33, order on reh’g, 168 FERC ¶ 61,170 (2019); *Cal. Pub. Utils. Comm’n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 at P 68; see also *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,136 at P 84, order on reh’g, 173 FERC ¶ 61,225 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242 at P 54, order on reh’g, 176 FERC ¶ 61,053 (2021).

³⁵⁸² NOPR, 179 FERC ¶ 61,028 at P 406.

³⁵⁸³ *Id.*

³⁵⁸⁴ We note that while transmission providers may not propose a kV threshold that exceeds 200 kV, they may propose a lower kV threshold (e.g., 100 kV or 115 kV), which would require transmission providers in that transmission planning region to include in their in-kind replacement estimates a wider range of transmission facilities that they own and anticipate replacing in-kind with a new transmission facility during the next 10 years.

Term Transmission Needs. Specifically, we believe adopting the 230 kV threshold proposed in the NOPR could have excluded from consideration some transmission facilities planned for in-kind replacement that are likely to provide regional benefits.³⁵⁸⁵ In adopting a specified kV threshold (so long as that threshold does not exceed 200 kV), as opposed to the 230 kV threshold proposed in the NOPR, we note that the Commission “has wide discretion to determine where to draw administrative lines.”³⁵⁸⁶

1684. We find that the requirement for transmission providers to identify a kV threshold not to exceed 200 kV to identify in-kind replacements recognizes that the NOPR proposal did not align with the region-specific characteristics outlined by some transmission providers. For example, as ISO-NE notes, a large portion of ISO-NE’s transmission system consists of 115 kV transmission facilities.³⁵⁸⁷ We find that the maximum kV threshold that we adopt allows flexibility for transmission providers, like ISO-NE, to tailor their proposed kV threshold to their specific transmission planning regions (as long as the threshold they apply is equal or lower than 200 kV), while ensuring that the in-kind replacement transmission facilities that are most susceptible to modification that could more efficiently or cost-effectively address Long-Term Transmission Needs are considered for right-sizing.

1685. With regard to the 10-year timeframe for in-kind replacement estimates, we believe that 10 years is an appropriate timeframe to evaluate potential in-kind replacement transmission facilities for right-sizing because it balances the long lead times associated with developing certain transmission facilities with the uncertainty associated with the exact timing of when aging transmission facilities may need to be replaced.³⁵⁸⁸

³⁵⁸⁵ For example, the maximum 200 kV threshold that we adopt here mirrors existing processes (e.g., CAISO) for determining whether a transmission facility provides regional benefits or more localized benefits. Appendix A of CAISO’s OATT defines a “Large Project” as “[a] transmission upgrade or addition that exceeds \$200 million in capital costs and consists of a proposed transmission line or substation facilities capable of operating at voltage levels greater than 200 kV.” CAISO, CAISO eTariff, app. A, Definitions (0.0.0), section Large Project. Moreover, we note that a 200 kV threshold aligns with the 200 kV threshold for interconnection reforms discussed in the Coordination of Regional Transmission Planning and Generator Interconnection Process section of this final order.

³⁵⁸⁶ *ExxonMobil Gas Mktg. Co. v. FERC*, 297 F.3d 1071, 1085 (D.C. Cir. 2002) (quoting *AT&T Corp. v. FCC*, 220 F.3d 607, 627 (D.C. Cir. 2000)).

³⁵⁸⁷ ISO-NE Initial Comments at 39.

³⁵⁸⁸ NOPR, 179 FERC ¶ 61,028 at P 406.

We also clarify that the 10-year timeframe for in-kind replacement estimates should reflect a transmission provider’s estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years beginning at the start of each Long-Term Regional Transmission Planning cycle. Furthermore, we believe that a 10-year timeframe is more likely to capture a larger pool of potential in-kind replacement transmission facilities that would be eligible for right-sizing. We recognize, however, that transmission providers may obtain better information about a transmission facility’s condition as the anticipated replacement date approaches and may also identify additional transmission facilities that require replacement in fewer than 10 years based on updated assessments of their condition. As such, we clarify that transmission providers may update the lists of transmission facilities that they anticipate replacing in subsequent transmission planning cycles if they believe that an anticipated in-kind replacement transmission facility is more urgently needed than previously thought or if existing transmission facilities do not deteriorate as quickly as previously expected.

1686. Several commenters oppose the right-sizing reform. They suggest that adopting the reform would harm competition or existing transmission planning processes that already evaluate whether replacement transmission facilities can be increased in transfer capability. We are unpersuaded by these arguments. We adopt the right-sizing reform because it captures certain transmission planning efficiencies by addressing aging transmission infrastructure issues while also providing an opportunity to increase transfer capability (i.e., develop the right-sized replacement transmission facility) to address Long-Term Transmission Needs more efficiently or cost-effectively. With respect to concerns about the right-sizing reform’s impact on competition, we address that issue below under the section on Rights of First Refusal. Regarding commenters’ arguments that existing transmission planning processes already evaluate whether replacement transmission facilities can be right-sized, we note that we require transmission providers to consider right-sizing as part of Long-Term Regional Transmission Planning. If transmission providers wish to continue to consider right-sizing

opportunities in some or all of their existing transmission planning processes in addition to Long-Term Regional Transmission Planning, this reform does not address those processes, and they may continue to adhere to existing practices that are not modified by this final order. Further, we emphasize that transmission providers may propose compliance approaches that are consistent with or superior to these requirements, and as such, depending on their individual circumstances and approaches, may be able to demonstrate that a method akin to their existing practice is also appropriate for right-sizing in Long-Term Regional Transmission Planning.

1687. In response to PJM States’ request for clarification regarding the interaction between existing processes and whether the right-sizing reform necessitates competitive transmission development processes, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing existing transmission facilities. Regarding PJM States’ request for clarification on competitive transmission development processes, we refer to the Right of First Refusal section below.

1688. In response to Exelon’s concerns regarding the timing of replacement transmission facilities, we clarify that the 10-year timeframe associated with the right-sizing reform applies to transmission facilities that a transmission provider *anticipates* replacing. In other words, the requirement for a transmission provider to include in its in-kind replacement estimates any transmission facilities that it anticipates replacing in-kind during the next 10 years does not create an obligation for the transmission provider to change any existing process that it has to identify which transmission facilities it anticipates replacing. However, a transmission provider must include in its in-kind replacement estimates any transmission facilities it anticipates replacing during the next 10 years beginning at the start of each Long-Term Regional Transmission Planning cycle, regardless of the process it uses to identify the facilities.

1689. In response to SERTP Sponsors and PG&E’s arguments that replacement decisions may be triggered more by the conditions of a particular transmission facility than its age, we reiterate, consistent with the statement the Commission made in the NOPR, we recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining, and when necessary,

replacing existing transmission facilities. We recognize that, as SERTP Sponsors note, replacement decisions may be triggered by other conditions than a transmission facility's age or condition, and since we recognize that a transmission provider may have existing rights and responsibilities under existing laws with respect to maintaining and, when necessary, replacing transmission facilities, we note that SERTP Sponsors, as well as any other transmission providers, may address such replacements of existing transmission facilities according to their existing processes.

1690. In response to Entergy's request for clarification regarding storm-hardening, we reiterate that the right-sizing reform we adopt here pertains to transmission facilities that a transmission provider anticipates replacing with an in-kind replacement transmission facility. To the extent that storm-hardening transmission projects do not encompass the replacement of existing transmission facilities with an in-kind replacement transmission facility, those storm-hardening transmission projects need not be included on a transmission provider's list of in-kind replacement estimates.

1691. In response to US DOE's argument that transmission providers should not be required to submit every in-kind replacement for all equipment, we clarify that the right-sizing reform we adopt here requires transmission providers to list in their in-kind replacement estimates *only* the transmission facilities operating at and above the specified kV threshold that they own and anticipate replacing in-kind with a new transmission facility during the next 10 years, provided transmission providers may not propose a specified kV threshold higher than 200 kV.

1692. WIRES requests that the Commission clarify that transmission providers would not be prohibited from considering right-sizing transmission facilities lower than 230 kV if existing transmission planning processes already do so. We clarify that, given our modification to the NOPR proposal, transmission providers may propose on compliance a threshold lower than 200 kV for considering right-sizing transmission facilities. We reiterate that the 200 kV threshold is a maximum threshold (*i.e.*, transmission providers may not propose a right-sizing threshold higher than 200 kV).

2. Right of First Refusal

a. NOPR Proposal

1693. In the NOPR, the Commission proposed, for any right-sized replacement transmission facility that is selected to meet transmission needs identified through Long-Term Regional Transmission Planning, to require the establishment of a Federal right of first refusal for the transmission provider that includes the in-kind replacement transmission facility in its in-kind replacement estimates, which would extend to any portion of such a transmission facility located within the applicable transmission provider's retail distribution service territory or footprint.³⁵⁸⁹

b. Comments

1694. Some commenters support the proposed Federal right of first refusal for right-sized replacement transmission facilities.³⁵⁹⁰ AEP argues that without it, transmission providers may develop an in-kind replacement facility instead of the right-sized transmission facility identified in the regional transmission planning process.³⁵⁹¹ Similarly, PG&E states that providing a Federal right of first refusal for right-sized replacement transmission facilities will provide an incentive for transmission providers to develop such projects, where appropriate.³⁵⁹²

1695. MISO TOs argue that, whether through in-kind replacement or right-sized replacement, "what is being done is an upgrade of an existing transmission facility," for which the Commission has afforded transmission owners Federal rights of first refusal through Order No. 1000 (and prior actions).³⁵⁹³ US Chamber of Commerce states that a Federal right of first refusal for right-sized replacement transmission facilities should also apply to right-sized transmission facilities, as it would eliminate incentives to withhold in-kind replacements from the regional transmission planning process.³⁵⁹⁴

1696. Ameren states that critics of the NOPR's proposal to provide transmission providers a Federal right of

first refusal for right-sizing projects question whether the Commission has met its FPA section 206 burden to demonstrate that the regional transmission planning tariffs are currently unjust and unreasonable or unduly discriminatory in order to justify this proposal.³⁵⁹⁵ Ameren contends that this argument misses a critical point because, currently, replacement of transmission facilities in-kind is generally not subject to the regional transmission planning process or competitive transmission development processes. Ameren asserts that the Commission need not find any existing rate unjust and unreasonable in order to signal an intent to approve such right of first refusals for right-sizing projects when filed with the Commission under FPA section 205.³⁵⁹⁶

1697. Several commenters oppose the proposed Federal right of first refusal for right-sized replacement transmission facilities.³⁵⁹⁷ Massachusetts Attorney General argues that the Commission has not demonstrated a "rational connection" between the Commission's findings and the right-sizing reform. Massachusetts Attorney General adds that the NOPR proposal is directly at odds with the Commission's findings in Order Nos. 890 and 1000 and that the Commission fails to provide "good reasons" for departing from those prior findings.³⁵⁹⁸ American Municipal Power argues that, even if incumbent transmission owners currently have a right of first refusal for local transmission facilities, that right should be limited to maintenance (*i.e.*, in-kind replacements) and not situations where a transmission facility would expand or

³⁵⁹⁵ Ameren Reply Comments at 14 (citing LS Power Initial Comments at 50).

³⁵⁹⁶ *Id.*

³⁵⁹⁷ AEE Reply Comments at 31; American Municipal Power Initial Comments at 28–29; Anbaric Initial Comments at 7; California Commission Initial Comments at 115–117; California Water Initial Comments at 8–9; City of New York Initial Comments at 11–13; Competition Coalition Initial Comments at 64; Competition Coalition Reply Comments at 2; Industrial Customers Initial Comments at 4; Kentucky Commission Chair Chandler Initial Comments at 19; LS Power Initial Comments at 22, 25–26, 84–85; Massachusetts Attorney General Initial Comments at 51–53; NextEra Initial Comments at 54–61; Northwest and Intermountain Initial Comments at 21–22; Pennsylvania Commission Initial Comments at 22–23; R Street Initial Comments at 3–4, 12–21; Resale Iowa Initial Comments at 8–9; TAPS Initial Comments at 68.

³⁵⁹⁸ Massachusetts Attorney General Initial Comments at 40, 51 (citing 5 U.S.C. 706(2); 16 U.S.C. 825(b); *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n of the U. S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)).

³⁵⁸⁹ *Id.* PP 408–409.

³⁵⁹⁰ AEP Initial Comments at 46–47; Ameren Reply Comments at 14–15; Dominion Initial Comments at 75; EEI Initial Comments at 41; Exelon Initial Comments at 58; MISO TOs Initial Comments at 27–28; PG&E Reply Comments at 15–16; US Chamber of Commerce Initial Comments at 11; Vermont Electric and Vermont Transco Initial Comments at 5.

³⁵⁹¹ AEP Initial Comments at 46–47 (citing NOPR, 179 FERC ¶ 61,028 at PP 408–409).

³⁵⁹² PG&E Reply Comments at 16.

³⁵⁹³ MISO TOs Initial Comments at 27–28.

³⁵⁹⁴ US Chamber of Commerce Initial Comments at 11 (citing NOPR, 179 FERC ¶ 61,028 at P 409).

enhance the transmission system.³⁵⁹⁹ LS Power argues that the right-sizing proposal changes definitions in Order No. 1000, including the definitions of an upgrade and a local transmission facility, and allows a Federal right of first refusal for transmission facilities located on an existing right-of-way instead of leaving the issue to state law.³⁶⁰⁰ LS Power asserts that, even if the Commission could meet the first prong of its section 206 analysis and find that the existing transmission planning process is unjust and unreasonable, the Commission must still establish that the entirety of the replacement rate is just and reasonable which, LS Power argues, the Commission cannot because of the tie to a Federal right of first refusal. Taken together, LS Power argues that the NOPR proposal, if adopted, would fail as a replacement rate.³⁶⁰¹ Furthermore, LS Power argues that the Federal right of first refusal for right-sized replacement transmission facilities would essentially provide a Federal franchise, mandating that transmission customers accept the ownership right of the existing transmission owners to continue in perpetuity.³⁶⁰²

1698. Northwest and Intermountain support clarifying that a Federal right of first refusal for right-sized replacement transmission facilities does not apply to any facilities that replace equipment that has reached the end of its useful life. Moreover, Northwest and Intermountain contend that the Commission should require a competitive solicitation for any right-sized transmission projects that meet regional transmission needs.³⁶⁰³ AEE contends that the record does not support further action on the proposed Federal right of first refusal for right-sized replacement transmission facilities, and instead reflects the complexity of the issues involved and the need for a holistic review of competitive transmission development processes and options for improving them.³⁶⁰⁴

1699. Several commenters raise concerns about the incentives that the proposed federal right of first refusal for right-sized replacement transmission

facilities would introduce.³⁶⁰⁵ Pennsylvania Commission argues that incumbent transmission owners may use it as a new tool to avoid competition by displacing other regional transmission facilities.³⁶⁰⁶ Given that transmission providers may not secure cost recovery for imprudently incurred expenses, NextEra disagrees that, without a Federal right of first refusal for right-sized replacement transmission facilities, incumbent transmission owners may engage in duplicative or inefficient transmission development.³⁶⁰⁷

1700. Some commenters oppose the proposed Federal right of first refusal for right-sized replacement transmission facilities because they argue that it would increase costs for customers.³⁶⁰⁸ California Water argues that allowing a Federal right of first refusal for right-sized replacement transmission facilities would permit incumbent transmission owners to construct right-sized transmission facilities without any cost guardrails, which could end up being more expensive than the in-kind replacements.³⁶⁰⁹ Alternatively, some commenters argue that their existing transmission planning processes already consider “right-sizing” replacement transmission facilities and may not include a Federal right of first refusal.³⁶¹⁰

1701. In response to claims that there is no logical basis for a Federal right of first refusal for right-sized replacement transmission facilities, MISO TOs state that the proposal applies to upgrades of an existing transmission facility and that in Order No. 1000, the Commission expressly reserved a Federal right of first refusal for an individual utility to upgrade its own property. As such, MISO TOs argue, a right-sizing requirement should neither deprive a transmission owner of its rights regarding its own property or its right to

construct and own upgrades to its own system, nor should it implement an unconstitutional taking of such owner’s property.³⁶¹¹ Therefore, MISO TOs state that the final order should clarify that nothing in the right-sizing proposal eliminates an incumbent transmission owner’s Federal right of first refusal for any transmission facilities selected through a right-sizing process.³⁶¹²

c. Commission Determination

1702. We adopt the NOPR proposal to require the establishment of a Federal right of first refusal for a right-sized replacement transmission facility³⁶¹³ that is selected to meet Long-Term Transmission Needs. This Federal right of first refusal will apply to the transmission provider that included in its in-kind replacement estimate the existing transmission facility that the right-sized replacement transmission facility would replace, and extends to any portion of the right-sized replacement facility located within that transmission provider’s retail distribution service territory or footprint, recognizing that any such portion must satisfy the definition of a right-sized replacement facility, as revised by this final order, including that the right-sized replacement transmission facility is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility.

1703. In adopting the NOPR proposal to require the establishment of a Federal right of first refusal for a right-sized replacement transmission facility, we find that permitting a Federal right of first refusal for right-sized replacement

³⁶¹¹ MISO TOs Reply Comments at 33 (citing Order No. 1000, 136 FERC ¶ 61,051 at PP 226, 319; Order No. 1000–A, 139 FERC ¶ 61,132 at P 426; *N.Y. Indep. Sys. Operator, Inc.*, 175 FERC ¶ 61,038, at PP 30, 33 (2021)).

³⁶¹² MISO TOs Reply Comments at 33 (citing MISO TOs Initial Comments at 25–28).

³⁶¹³ As noted above, right-sizing could include, for example, increasing the transmission facility’s voltage level, adding circuits to the towers (*e.g.*, redesigning a single-circuit line as a double-circuit line), or incorporating advanced technologies (*e.g.*, advanced conductor technologies). Additionally, we reiterate that, as noted above, a right-sized replacement transmission facility is, for purposes of this right-sizing reform, a new transmission facility that: (1) would meet the need to replace an existing transmission facility that a transmission provider has identified in its in-kind replacement estimate as one that it plans to replace with an in-kind replacement transmission facility while also addressing a Long-Term Transmission Need; (2) results in more than an incidental increase in the capacity of an existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate; and (3) is located in the same general route as, and/or uses or expands the existing rights-of-way of, the existing transmission facility that a transmission provider has identified for replacement in its in-kind replacement estimate.

³⁵⁹⁹ American Municipal Power Initial Comments at 28.

³⁶⁰⁰ LS Power Initial Comments at 22.

³⁶⁰¹ *Id.* at 147–48 (citing *Nat’l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831, 845 (D.C. Cir. 2006); *SEC v. Chenery Corp.*, 318 U.S. 80, 95 (1943)).

³⁶⁰² *Id.* at 84–85.

³⁶⁰³ Northwest and Intermountain Initial Comments at 21–22.

³⁶⁰⁴ AEE Reply Comments at 31.

³⁶⁰⁵ Anbaric Initial Comments at 7; California Commission Initial Comments at 114–115; Competition Coalition Initial Comments at 65–67; LS Power Initial Comments at 81–82; Massachusetts Attorney General Initial Comments at 51–52; NextEra Initial Comments at 58; Pennsylvania Commission Initial Comments at 22; Resale Iowa Initial Comments at 8–9.

³⁶⁰⁶ Pennsylvania Commission Initial Comments at 22.

³⁶⁰⁷ NextEra Initial Comments at 59–61 (citations omitted).

³⁶⁰⁸ See California Commission Initial Comments at 117; California Water Initial Comments at 9; Competition Coalition Initial Comments at 66–67; DC and MD Offices of People’s Counsel Initial Comments at 47–48; R Street Reply Comments at 5–6; State Agencies Initial Comments at 21–22.

³⁶⁰⁹ California Water Initial Comments at 9.

³⁶¹⁰ CAISO Initial Comments at 47–49; New York Commission and NYSEDA Initial Comments at 15–16; New York TOs Initial Comments at 17–18; NYISO Initial Comments at 58–59.

transmission facilities will encourage transmission providers to provide their best in-kind replacement estimates, because they will have certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility. As such, we find that a Federal right of first refusal will remove a disincentive for transmission providers to consider right-sizing in Long-Term Regional Transmission Planning, helping to ensure that the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs is selected and likely built, and therefore that Commission-jurisdictional rates are just and reasonable. Moreover, we note that the definitions of “in-kind replacement transmission facility” and “right-sized replacement transmission facility” that we adopt, as discussed above, are necessary to ensure that use of the right-sizing reform addresses *replacement* transmission facilities and not entirely new transmission facilities.³⁶¹⁴

1704. We note that the establishment of a Federal right of first refusal for right-sized replacement transmission facilities is an exception to Order No. 1000’s general requirement for transmission providers to eliminate any Federal right of first refusal for regional transmission facilities selected in a regional transmission plan.³⁶¹⁵ In response to comments challenging this approach as violating the precedent set in Order No. 1000, which eliminated Federal rights of first refusal for new selected transmission facilities,³⁶¹⁶ we find that requiring a Federal right of first refusal for right-sized replacement transmission facilities aligns with Order No. 1000.

1705. In Order No. 1000, the Commission required transmission providers to remove Federal rights of first refusal from their OATTs because they undermined the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level, which could lead to unjust and unreasonable rates for Commission-jurisdictional services.³⁶¹⁷ The Commission found that Federal rights of first refusal created a barrier to entry that discouraged nonincumbent transmission developers from proposing alternative solutions for consideration at the regional level.³⁶¹⁸ The Commission did not require the elimination of

Federal rights of first refusal for local transmission facilities,³⁶¹⁹ and did not alter the rights of incumbent transmission providers to build, own, and recover costs for upgrades to its own transmission facilities, regardless of whether the upgrade is selected.³⁶²⁰

1706. We find that the Commission’s reasons for removing Federal rights of first refusal in Order No. 1000 do not apply to right-sized replacement transmission facilities. Specifically, requiring a Federal right of first refusal for right-sized replacement transmission facilities does not undermine the consideration of more efficient or cost-effective potential transmission solutions proposed at the regional level; rather, we find that it will *promote* the consideration of more efficient or cost-effective potential regional transmission solutions to address Long-Term Transmission Needs. When compared against the alternative of piecemeal development of in-kind replacement transmission facilities, a Federal right of first refusal for right-sized transmission facilities does not frustrate the goals of Order No. 1000 or lead to inefficiency in transmission development because the right-sized replacement transmission facility represents the more efficient or cost-effective regional transmission solution to address Long-Term Transmission Needs (otherwise it would not be selected). We recognize that a transmission provider may have existing rights and responsibilities with respect to maintaining and, when necessary, replacing their transmission facilities. Because the right-sizing reform does not alter existing laws related to an individual transmission provider’s ability to proceed with an in-kind replacement transmission facility, absent a Federal right of first refusal, we believe the incumbent transmission provider whose in-kind replacement transmission facility is selected to be right-sized would likely proceed to develop the less efficient or cost-effective in-kind replacement transmission facility. We find that the transmission provider would prefer the assurance of a Federal right of first refusal for the in-kind replacement transmission facility over the uncertainty of subjecting a right-sized replacement transmission facility to the Order No. 1000 competitive transmission development process. Because of this incentive structure and the fact that the transmission provider holds the leverage as to whether to build a right-sized replacement transmission facility or a less efficient in-kind

replacement transmission facility, the establishment of the Federal right of first refusal is necessary to effectuate this reform and ensure that Commission-jurisdictional rates are just and reasonable.³⁶²¹

1707. By establishing a process that requires transmission providers to evaluate opportunities to right-size in-kind replacement transmission facilities to meet Long-Term Transmission Needs, and by establishing a Federal right of first refusal for such right-sized replacement transmission facilities, we believe that the right-sizing reform in this final order will encourage transmission providers to provide their best in-kind replacement estimates, as they will have certainty that they will not lose the opportunity to invest in any in-kind replacement transmission facility that is then selected as a right-sized replacement transmission facility. Moreover, permitting a Federal right of first refusal for right-sized replacement transmission facilities will enable transmission providers to ensure that the more efficient or cost-effective regional transmission solution to Long-Term Transmission Needs is selected and that Commission-jurisdictional rates are consequently just and reasonable.³⁶²²

1708. In response to MISO TOs’ request regarding upgrades to existing transmission facilities, we reiterate that nothing in the right-sizing reform affects the right of an incumbent transmission provider to build, own, and recover the costs for upgrades to its own transmission facilities, regardless of whether an upgrade to an existing transmission facility has been identified through a right-sizing process and selected to address Long-Term Transmission Needs.

1709. We deny Northwest and Intermountain’s request to clarify that the right-sizing reform excludes transmission facilities that replace equipment that has reached the end of its useful life. As explained above, the Federal right of first refusal will apply to selected right-sized replacement

³⁶²¹ See NOPR, 179 FERC ¶ 61,028 at P 408 & n.652.

³⁶²² In response to those commenters who argue that their existing transmission planning processes already consider “right-sizing” replacement transmission facilities without the inclusion of a Federal right of first refusal, we note that, separate from compliance with this final order, transmission providers in each transmission planning region can agree to participant funding arrangements for right-sized replacement transmission facilities that are not selected through Long-Term Regional Transmission Planning, in which case the requirement to establish a Federal right of first refusal for right-sized replacement transmission facilities selected to meet Long-Term Transmission Needs would not apply.

³⁶¹⁴ See *supra* PP 1681–1683.

³⁶¹⁵ See *supra* P 1576.

³⁶¹⁶ Order No. 1000, 136 FERC ¶ 61,051 at P 313.

³⁶¹⁷ *Id.* PP 253, 256.

³⁶¹⁸ *Id.* P 257.

³⁶¹⁹ *Id.* P 318.

³⁶²⁰ *Id.* P 319 (citation omitted).

transmission facilities, including those that are intended to replace transmission facilities that have reached the end of their useful life.

3. Cost Allocation

a. NOPR Proposal

1710. With respect to cost allocation, the Commission proposed that if a right-sized replacement transmission facility is selected, only the incremental costs of right-sizing the transmission facility would be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method. The Commission proposed that the costs the incumbent transmission provider would have otherwise incurred to construct the in-kind replacement transmission facility be allocated in a manner consistent with the allocation that would have otherwise occurred for the in-kind replacement. The Commission preliminarily found that it is just and reasonable and not unduly discriminatory or preferential for only the portion of the costs associated with a right-sized replacement transmission facility that is selected to be eligible to use the Long-Term Regional Transmission Cost Allocation Method because it is the right-sizing of the in-kind replacement transmission facility that allows the transmission facility to meet the transmission needs identified in Long-Term Regional Transmission Planning.³⁶²³

1711. The Commission also proposed to require transmission providers in each transmission planning region to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected (and thus found to be a more efficient or cost-effective transmission facility to meet regional transmission needs) and which transmission facilities are simply included in the regional transmission plan for informational (and not cost allocation) purposes.³⁶²⁴

b. Comments

1712. Some commenters support the NOPR proposal that the incremental costs of right-sizing a transmission facility that is selected would be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method.³⁶²⁵ ACEG contends that without it, a large amount of new transmission investment—directed

solely at replacement facilities—will be outside of Long-Term Regional Transmission Planning and thus not given an opportunity to contribute to the grid's overall efficiency and cost-effectiveness.³⁶²⁶ Eversource asserts that, in New England, asset condition projects receive regional cost allocation, and requests clarification that the Commission is not proposing to disturb the existing cost allocation method for asset condition projects in ISO-NE that are not selected for right-sizing in Long-Term Regional Transmission Planning.³⁶²⁷ NESCOE recommends that the Commission require transmission providers to explain on compliance the method that they will use to determine the incremental costs of right-sizing a replacement transmission facility. In addition, NESCOE supports the proposal to require transmission providers to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected.³⁶²⁸

1713. Other commenters support the proposed cost allocation for right-sized replacement transmission facilities, but express reservations.³⁶²⁹ Entergy asserts that the Commission should clarify that costs incurred absent right-sizing will be allocated under the cost allocation method(s) that otherwise would apply to such costs, which may include regional cost allocation.³⁶³⁰ With regard to incremental costs, CTC Global urges the Commission to require the transmission planning process to be based on future needs, future benefits, total lifecycle costs, and total benefits for the life of the resource. More specifically, CTC Global suggests that when considering incremental costs, the Commission should consider including energy savings, generating capacity reduction benefits, and resulting reductions in greenhouse gas emissions as benefits associated with the right-sized replacement transmission facility.³⁶³¹

1714. Dominion states that it may be difficult to quantify and allocate the incremental costs of right-sizing a replacement transmission facility.³⁶³² MISO agrees, stating that it will be challenging to identify the portion of

costs that should be recovered as part of the age and condition upgrade using one cost allocation method and a different cost allocation for the portion of the right-sized upgrade identified as part of Long-Term Regional Transmission Planning. MISO argues that this complexity will continue going forward given that the accounting for two types of cost allocation to different customers will have to be tracked for each right-sized replacement transmission facility.³⁶³³

1715. Some commenters oppose the NOPR proposal.³⁶³⁴ LS Power argues that the proposal violates cost causation principles as it would limit regional cost allocation to the incremental portion of the right-sized replacement transmission facilities, regardless of beneficiary analysis.³⁶³⁵ Indicated PJM TOs state that the Commission should not impose any requirements with respect to the cost allocation of right-sized replacement transmission facilities and instead should provide transmission providers with the flexibility to determine a cost allocation method.³⁶³⁶ Exelon agrees, adding that the Commission's proposed approach creates unnecessary complications and adds a further variable (base versus incremental cost) to the already complex and often contentious cost allocation process. According to Exelon, the proposal (1) incorrectly assumes that a transmission owner has identified an in-kind replacement transmission facility and its cost; (2) incorrectly assumes that a perfect overlap exists between the displaced transmission facility (or need) and the right-sized replacement transmission facility; and (3) fails to address adjustments for cost savings or overruns on the right-sized portion of the transmission facility.³⁶³⁷

c. Commission Determination

1716. We decline to adopt the NOPR proposal to require that, if a right-sized replacement transmission facility is selected, only the incremental costs of right-sizing the transmission facility will be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method, while the costs that the transmission provider would otherwise have incurred to construct the in-kind replacement transmission

³⁶²⁶ ACEG Initial Comments at 57–58.

³⁶²⁷ Eversource Initial Comments at 54.

³⁶²⁸ NESCOE Initial Comments at 81.

³⁶²⁹ CTC Global Initial Comments at 19; Dominion Initial Comments at 75–76; Entergy Initial Comments at 39; MISO Initial Comments at 87; NRG Initial Comments at 36–37.

³⁶³⁰ Entergy Initial Comments at 39.

³⁶³¹ CTC Global Initial Comments at 19.

³⁶³² Dominion Initial Comments at 75–76.

³⁶³³ MISO Initial Comments at 87.

³⁶³⁴ Exelon Initial Comments at 59; Indicated PJM TOs Initial Comments at 47; LS Power Initial Comments at 86–87.

³⁶³⁵ LS Power Initial Comments at 86–87 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, reh'g denied, 905 F.3d 671 (D.C. Cir. 2018)).

³⁶³⁶ Indicated PJM TOs Initial Comments at 47 (citation omitted).

³⁶³⁷ See Exelon Initial Comments at 59 & n.103.

³⁶²³ NOPR, 179 FERC ¶ 61,028 at P 410.

³⁶²⁴ *Id.* P 413.

³⁶²⁵ ACEG Initial Comments at 57–58; Eversource Initial Comments at 54; NARUC Initial Comments at 65; NESCOE Initial Comments at 81.

facility must be allocated in a manner consistent with the allocation that would have otherwise occurred for the in-kind replacement transmission facility. This is because we find persuasive comments that identify the complexities and challenges associated with tracking portions of costs of two different transmission projects through time, as well as allocating the costs of a right-sized replacement transmission facility pursuant to two separate cost allocation methods.³⁶³⁸ While the approach that the NOPR proposed to require may still be a just and reasonable cost allocation approach for right-sized replacement transmission facilities, should the relevant transmission providers *choose* to take on these challenges and address them adequately, we find it appropriate to provide flexibility to transmission providers to propose a cost allocation method for selected right-sized replacement transmission facilities. However, in providing such flexibility, transmission providers must nevertheless demonstrate on compliance that the cost allocation method for selected right-sized replacement transmission facilities is just and reasonable and not unduly discriminatory or preferential and, consistent with cost causation, allocates costs in a manner that is at least roughly commensurate with the estimated benefits of such facilities.³⁶³⁹

1717. Further, we also require transmission providers in each transmission planning region to amend their regional transmission planning processes to provide transparency with respect to which right-sized replacement transmission facilities have been selected, as well as which transmission facilities are simply included in the regional transmission plan for informational (and not cost allocation) purposes.

1718. We disagree with LS Power's assertion that the right-sizing cost allocation method proposed in the NOPR violates cost causation principles because it would limit regional cost allocation to the incremental portion of the right-sized replacement transmission facilities, regardless of other potential beneficiaries.³⁶⁴⁰ The customers of the transmission provider

that would be allocated the costs associated with the original in-kind replacement transmission facility would have otherwise been responsible for paying those costs had the in-kind replacement transmission facility not been right-sized. Further, we find that it is not unjust, unreasonable, or unduly discriminatory or preferential that, for a right-sized replacement transmission facility selected, only the portion of the costs associated with right-sizing be eligible to use the Long-Term Regional Transmission Cost Allocation Method. Specifically, we find that it is the right-sizing of the in-kind replacement transmission facility that allows the transmission facility to meet Long-Term Transmission Needs identified in Long-Term Regional Transmission Planning. As such, we disagree that allowing only the incremental costs of right-sizing the right-sized replacement transmission facility to be eligible to use the applicable Long-Term Regional Transmission Cost Allocation Method would violate cost causation principles.

1719. As we note above, we find merit with respect to commenters' concerns about the difficulty in determining the portion of the costs of a right-sized replacement transmission facility attributable to right-sizing and the complexity in tracking portions of differing cost allocation methods through time. For this reason, to the extent that transmission providers propose to allocate the costs of right-sized replacement transmission facilities pursuant to the cost allocation method described in the NOPR, we require the transmission providers to explain on compliance (1) the method that they will use to determine the portion of the costs of a right-sized replacement transmission facility that is incremental to the costs that would have been incurred for the underlying in-kind replacement transmission facility, and (2) the method by which they will track the portion of costs over time that are allocated in accordance with the Long-Term Regional Transmission Cost Allocation Method (or, if adopted, subject to a State Agreement Process), as well as the portion of costs that would have been allocated pursuant to the cost allocation method that otherwise would have applied to the in-kind replacement transmission facility. We believe that transmission providers are best positioned to determine both the portion of the costs of a right-sized replacement transmission facility that is incremental to the costs that would have been incurred for the underlying in-kind replacement transmission facility, as well as how to best track these costs

over time for purposes of cost allocation.

1720. In response to Eversource and Entergy's requests that the Commission clarify the cost allocation method for in-kind replacement transmission facilities that are not selected for right-sizing,³⁶⁴¹ we clarify that we are not requiring any changes pursuant to this right-sizing requirement that would affect the existing cost allocation method(s) for in-kind replacement transmission facilities that are not identified for right-sizing, or for the costs of the underlying in-kind replacement transmission facilities that would have been incurred absent right-sizing. Similarly, in response to Entergy's request for clarification that costs incurred absent right-sizing will be allocated under the cost allocation method(s) that otherwise would apply to such costs, which may include regional cost allocation, we clarify that the costs that the transmission provider would otherwise have incurred to construct the in-kind replacement transmission facility must be allocated in a manner consistent with the cost allocation method that would have otherwise applied to that facility, which could include a regional cost allocation method.

1721. We also confirm, in response to comments from CTC Global, that benefits associated with a potential right-sized replacement transmission facility to address Long-Term Transmission Needs should be evaluated in the same manner as for any potential regional transmission facility that could address those needs, which includes evaluating all of the costs of, and all of the benefits provided by, the right-sized replacement transmission facility consistent with reforms outlined in this final order.

1722. In response to Exelon's comments that the NOPR proposal relies on incorrect assumptions regarding the transmission provider identifying an in-kind replacement transmission facility and its cost, as well as there being an overlap between the displaced transmission facility and the right-sized replacement transmission facility, we disagree and note that these conditions are prerequisites that serve as the foundation for the right-sizing requirement. Where a transmission provider has not identified an in-kind replacement transmission facility that could be right-sized to address Long-Term Transmission Needs more efficiently or cost-effectively, no basis exists to select a right-sized replacement transmission facility.

³⁶⁴¹ Entergy Initial Comments at 39; Eversource Initial Comments at 54.

³⁶³⁸ Dominion Initial Comments at 75–76; Exelon Initial Comments at 59; MISO Initial Comments at 87.

³⁶³⁹ See *ICC v. FERC I*, 576 F.3d at 477; Order No. 1000, 136 FERC ¶ 61,051 at PP 622, 639 (requiring costs of regional transmission facilities to be allocated in a manner that is at least roughly commensurate with estimated benefits).

³⁶⁴⁰ LS Power Initial Comments at 86–87 (citing *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254).

4. Miscellaneous

a. Comments

1723. Some commenters recommend that the Commission adopt confidentiality safeguards.³⁶⁴² AEP and Indicated PJM TOs contend that the Commission must adopt confidentiality provisions to ensure that information related to right-sizing is not shared beyond the regional planning entity because identification of end-of-life transmission facilities demonstrates potential vulnerabilities that could create security and reliability risks and could also provide advantages to competitors.³⁶⁴³ WIRES argues that the Commission should allow for the transmission owner to provide to the transmission provider a non-public, confidential, non-binding list of transmission facilities that may need to be replaced based on an appropriate time horizon as determined by the transmission provider.³⁶⁴⁴ SERTP Sponsors request that the Commission protect CEII information for transmission facilities that are anticipated to be replaced.³⁶⁴⁵

1724. Conversely, PJM States request that the Commission require the information on the in-kind replacement estimate list to be non-confidential to the greatest extent possible or to require justification as to why confidentiality is merited.³⁶⁴⁶

1725. Several commenters call for the Commission to increase scrutiny on, or alter the presumption of prudence for, transmission projects related to the right-sizing reform.³⁶⁴⁷ American Municipal Power argues that if an incumbent transmission owner replaces local transmission facilities at the end of their useful lives despite a determination that a right-sized replacement transmission facility is the more efficient or cost-effective transmission solution, the incumbent transmission owner's in-kind replacement should be presumed to be

unjust and unreasonable for purposes of cost recovery.³⁶⁴⁸

1726. ACEG asserts that the Commission has the authority under FPA section 205 to review replacement transmission facility projects and address problems in the local transmission planning process.³⁶⁴⁹ LS Power argues that the Commission should use its existing authority to confirm through show cause orders that transmission providers are evaluating whether local transmission solutions can be displaced by a regional transmission solution that is more efficient or cost-effective.³⁶⁵⁰

1727. Similarly, TAPS asserts that the NOPR imposes no consequences on transmission owners that proceed with in-kind replacement projects even when the transmission planning region has selected more efficient and cost-effective alternatives for regional cost allocation. TAPS argues that the Commission should exclude cost recovery for such facilities from the scope of formula rates and require transmission owners to make a separate filing pursuant to FPA section 205. Alternatively, TAPS states that the Commission should impose a presumption of imprudence and require such transmission owners to demonstrate that the proposed replacement is more cost-effective and efficient than the alternative selected by the transmission planning region.³⁶⁵¹

1728. On the other hand, PG&E argues that the Commission should clarify that a transmission owner's right to decline to proceed with a selected right-sized replacement transmission facility does not justify disallowance of cost recovery for the in-kind replacement transmission facility.³⁶⁵²

1729. Several commenters support consideration of alternative transmission technologies and grid enhancing technologies when evaluating right-sized replacement transmission facilities.³⁶⁵³ CTC Global urges the Commission to require all transmission owners with a line requiring in-kind replacement within 10 years to analyze whether a transmission line's conductor should be replaced with an advanced conductor through

rebuild or reconducting.³⁶⁵⁴ PIOs argue that right-sizing opportunities should include increasing voltage, adding circuits, and utilizing advanced technologies, and further argue that right-sized replacement transmission facilities that use grid enhancing technologies can create economies of scale to capture public policy and economic benefits in addition to reliability.³⁶⁵⁵ VEIR agrees with the Commission's proposal to include advanced conductors in its definition of right-sizing, explaining that superconductors can enable a five-fold increase in the power flow capacity of an existing transmission corridor. VEIR therefore urges the Commission to explicitly affirm that the deployment of advanced conductors would constitute right-sizing.³⁶⁵⁶

1730. Some commenters argue that the NOPR's right-sizing proposal is insufficient and call upon the Commission to take further action.³⁶⁵⁷ For example, ACEG, American Municipal Power, and California Commission argue that the Commission should expand the scope of the right-sizing proposal.³⁶⁵⁸ American Municipal Power argues that the Commission should require RTOs/ISOs to plan for all new transmission facilities that have regional impacts, including: (1) transmission facilities that meet the North American Electric Reliability Corporation Bulk Electric System definition; and (2) transmission projects that will replace an existing transmission facility that was turned over to the RTO/ISO irrespective of the voltage.³⁶⁵⁹ Similarly, LS Power argues that the Commission has the authority to require regional transmission planning for existing transmission facilities reaching the end of operational life, and that such transmission

³⁶⁵⁴ CTC Global Initial Comments at 18.

³⁶⁵⁵ PIOs Initial Comments at 57–58 (citing PIOs ANOPR Initial Comments at 50).

³⁶⁵⁶ VEIR Initial Comments at 6.

³⁶⁵⁷ ACEG Initial Comments at 57; American Municipal Power Initial Comments at 25–26; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 106–108; California Water Initial Comments at 10; Competition Coalition Initial Comments at 68–70; Grid United Initial Comments at 3–4; Harvard ELI Initial Comments at 4–5; LS Power Initial Comments at 136, 138, 141–142, 145–146; Ohio Consumers Initial Comments at 24; PIOs Initial Comments at 53; TAPS Initial Comments at 6, 64–65.

³⁶⁵⁸ See ACEG Initial Comments at 57–58; American Municipal Power Initial Comments at 25–26; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 113–118.

³⁶⁵⁹ American Municipal Power Reply Comments at 5.

³⁶⁴² AEP Initial Comments at 46; Exelon Initial Comments at 57–58; Indicated PJM TOs Initial Comments at 45–46; SERTP Sponsors Initial Comments at 39; WIRES Initial Comments at 10.

³⁶⁴³ AEP Initial Comments at 46; Indicated PJM TOs Initial Comments at 45.

³⁶⁴⁴ WIRES Initial Comments at 10.

³⁶⁴⁵ SERTP Sponsors Initial Comments at 39.

³⁶⁴⁶ PJM States Initial Comments at 7–8.

³⁶⁴⁷ American Municipal Power Initial Comments at 29–30; California Commission Initial Comments at 114–115; California Water Initial Comments at 9; Harvard ELI Initial Comments at 5; Massachusetts Attorney General Initial Comments at 52; Ohio Consumers Initial Comments at 23–24; Pine Gate Initial Comments at 49–50; PIOs Initial Comments at 58; Resale Iowa Initial Comments at 9; TAPS Initial Comments at 6–7, 67–68.

³⁶⁴⁸ American Municipal Power Initial Comments at 29.

³⁶⁴⁹ ACEG Initial Comments at 57.

³⁶⁵⁰ LS Power Initial Comments at 145 (citing LS Power ANOPR Initial Comments at 134–135).

³⁶⁵¹ TAPS Initial Comments at 6–7, 67–68 (citations omitted).

³⁶⁵² PG&E Initial Comments at 14.

³⁶⁵³ CTC Global Initial Comments at 18, 20; Maryland Energy Administration Reply Comments at 5–6; NARUC Initial Comments at 58–59; PIOs Initial Comments at 57–58; VEIR Initial Comments at 6.

planning should be performed by an independent transmission planner.³⁶⁶⁰

1731. Massachusetts Attorney General asserts that all right-sized replacement transmission facilities should be subject to cost containment, stating that transmission owners may present transmission projects that look like good opportunities for right-sizing at low cost, but without cost containment and competition, the final cost could be much higher.³⁶⁶¹ ACEG argues that the Commission could issue policy guidance regarding its scope and process for review of new replacement transmission facilities in transmission rate cases.³⁶⁶²

1732. Competition Coalition and LS Power argue that the Commission should protect customers by expanding the benefits of regional transmission planning and competition to all transmission projects 100 kV and above.³⁶⁶³ Ameren responds that this request by LS Power to expand the range of transmission projects subject to competition is outside the scope of the NOPR.³⁶⁶⁴

1733. Harvard ELI favors additional scrutiny of right-sized replacement transmission facilities. Harvard ELI states generally that the Commission could address the perverse incentives of current rules leading to a focus on local transmission development by subjecting local transmission planning to heightened scrutiny.³⁶⁶⁵

1734. PIOs claim that the Commission should consider an “ROE subtractor” analogous to an ROE adder that automatically reduces ROE with certain criteria.³⁶⁶⁶

b. Commission Determination

1735. We decline to adopt ACEG’s and LS Power’s requests that the Commission *itself* review in-kind replacement transmission facilities, via section 205 or 206 authority or through policy guidance, to ensure that they cannot be displaced by a regional transmission solution that is more efficient or cost-effective.³⁶⁶⁷ These

arguments are outside the scope of this proceeding because the Commission did not propose in the NOPR that the Commission review in-kind replacement transmission facilities or local transmission facilities.

1736. We decline to adopt commenters’ requests for additional confidentiality safeguards related to right-sizing.³⁶⁶⁸ We note that a transmission provider’s list of in-kind replacement estimates (*i.e.*, estimates of the transmission facilities operating at and above the specified kV threshold that an individual transmission provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years) is a non-binding estimate and does not require that transmission provider to undertake replacement work. To the extent that customers or stakeholders request access to a transmission provider’s list of in-kind replacement estimates, that transmission provider may subject access to that list of in-kind replacement estimates to confidentiality provisions. However, once the transmission providers have determined, as part of Long-Term Regional Transmission Planning, that an in-kind replacement transmission facility can be right-sized to constitute a right-sized replacement transmission facility, we find that the transmission providers must make public the underlying in-kind replacement transmission facility.

1737. We decline to adopt commenter requests for increased scrutiny of, or altering the presumption of prudence for, transmission projects related to right-sizing.³⁶⁶⁹ We reject these requests as outside the scope of this proceeding because the Commission did not propose in the NOPR to increase scrutiny of in-kind replacement transmission facilities beyond the right-sizing proposal and did not propose to alter existing Commission policy on prudence. Likewise, in response to PG&E’s request for clarification that a transmission provider’s declining to proceed with a right-sized replacement transmission facility does not justify

(citing LS Power ANOPR Initial Comments at 134–135).

³⁶⁶⁸ AEP Initial Comments at 46; Exelon Initial Comments at 57–58; Indicated PJM TOs Initial Comments at 45–46; SERTP Sponsors Initial Comments at 39; WIRES Initial Comments at 10.

³⁶⁶⁹ American Municipal Power Initial Comments at 29–30; California Commission Initial Comments at 114–115; California Water Initial Comments at 9; Harvard ELI Initial Comments at 4; Massachusetts Attorney General Initial Comments at 52; Mississippi Commission Initial Comments at 30; Ohio Consumers Initial Comments at 23; Pine Gate Initial Comments at 49–50; PIOs Initial Comments at 58; Resale Iowa Initial Comments at 9; TAPS Initial Comments at 6–7, 67.

disallowance of cost recovery for the in-kind replacement transmission facility, nothing in the reforms we adopt here alters existing Commission policy on cost recovery for transmission facilities.³⁶⁷⁰

1738. We acknowledge commenter support for the consideration of alternative transmission technologies with regard to right-sizing.³⁶⁷¹ However, we find that adopting additional requirements for consideration of alternative transmission technologies with respect to right-sizing are unnecessary. This is because, as discussed in the Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices section of this final order, we require transmission providers in each transmission planning region to more fully consider, in Long-Term Regional Transmission Planning and existing Order No. 1000 regional transmission planning, dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching.³⁶⁷² We believe that the requirements in the Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices section of this final order adequately address consideration of alternative transmission technologies in the regional transmission planning process, including when considering right-sizing.

1739. Some commenters request that the Commission take other actions and suggest alternative reforms to the Commission’s proposal related to right-sizing.³⁶⁷³ We find these requests to be outside the scope of this proceeding and lacking in record support to adequately

³⁶⁷⁰ *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985) (explaining that the Commission evaluates “prudence of the utility’s actions and the costs resulting therefrom based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses”).

³⁶⁷¹ CTC Global Initial Comments at 18, 20; Maryland Energy Administration Reply Comments at 5–6; NARUC Initial Comments at 58–59, 63–64; PIOs Initial Comments at 57–58; VEIR Initial Comments at 6.

³⁶⁷² See Consideration of Dynamic Line Ratings and Advanced Power Flow Control Devices section.

³⁶⁷³ ACEG Initial Comments at 57; American Municipal Power Initial Comments at 5, 25; American Municipal Power Reply Comments at 5; California Commission Initial Comments at 106–108; California Water Initial Comments at 10; Competition Coalition Initial Comments at 68–69; Grid United Initial Comments at 3–4; Harvard ELI Initial Comments at 4; LS Power Initial Comments at 83, 136, 138, 141–142, 145–146; Massachusetts Attorney General Initial Comments at 52; Ohio Consumers Initial Comments at 24; PIOs Initial Comments at 53; TAPS Initial Comments at 6, 64–65.

³⁶⁶⁰ LS Power Initial Comments at 83–84, 141 (citations omitted).

³⁶⁶¹ Massachusetts Attorney General Initial Comments at 52.

³⁶⁶² ACEG Initial Comments at 57 (citation omitted).

³⁶⁶³ Competition Coalition Initial Comments at 68–69; LS Power Initial Comments at 136, 141 (citations omitted); LS Power and NRG Post-Technical Conference Comments at 10 & n.17 (noting that its comment on this issue is attributed to LS Power only).

³⁶⁶⁴ Ameren Reply Comments at 15 (citing LS Power Initial Comments at 116).

³⁶⁶⁵ Harvard ELI Initial Comments at 4.

³⁶⁶⁶ PIOs Initial Comments at 53.

³⁶⁶⁷ ACEG Initial Comments at 57 (citations omitted); LS Power Initial Comments at 145–146

consider whether to adopt them in this final order.

X. Interregional Transmission Coordination

A. NOPR Proposal

1740. In the NOPR, the Commission proposed to require each transmission provider to revise its existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms proposed in the NOPR.³⁶⁷⁴

1741. Specifically, the Commission proposed to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission planning processes as needed) to provide for: (1) the sharing of information regarding their respective transmission needs identified in Long-Term Regional Transmission Planning, as well as potential transmission facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address transmission needs identified through Long-Term Regional Transmission Planning.³⁶⁷⁵

1742. The Commission also proposed to require transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to transmission needs identified through Long-Term Regional Transmission Planning.³⁶⁷⁶ The Commission noted that this proposal would align the existing requirement for an entity to propose an interregional transmission facility in the regional transmission planning processes of each of the neighboring transmission planning regions in which the transmission facility is proposed to be located with the proposed requirement for transmission providers to conduct Long-Term Regional Transmission Planning as part of their regional transmission planning processes.

1743. The Commission stated that this proposed reform aims to ensure that transmission needs driven by changes in the resource mix and demand identified through Long-Term Regional Transmission Planning can be

considered in existing interregional transmission coordination and cost allocation processes.³⁶⁷⁷ The Commission preliminarily concluded that the proposed interregional transmission coordination reforms will also ensure that there is an opportunity for the transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could more efficiently or cost-effectively meet the transmission needs identified through Long-Term Regional Transmission Planning, in turn helping to ensure just and reasonable Commission-jurisdictional rates.

B. Comments

1744. Many commenters support the Commission's proposal to require transmission providers to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms proposed in the NOPR.³⁶⁷⁸ Such commenters assert that this proposed reform would give transmission providers in neighboring transmission planning regions the opportunity to consider whether interregional transmission facilities could meet the transmission needs identified through Long-Term Regional Transmission Planning in a more efficient or cost-effective manner than separate regional transmission facilities, which would help to ensure just and reasonable rates.

1745. Some commenters condition their support on the Commission providing transmission providers with flexibility. For example, EEI asserts that

providing transmission providers with flexibility in developing Long-Term Regional Transmission Planning will help ensure that transmission planning regions can determine the processes that work for them and collaborate with neighboring regions.³⁶⁷⁹ Idaho Power requests that the Commission allow flexibility in the methods used to determine transmission benefits.³⁶⁸⁰ Pennsylvania Commission conditions its support on the Commission maintaining flexibility for transmission providers to define criteria for considering and selecting transmission facilities, including criteria that permit the selection of proposed regional transmission facilities over a proposed interregional transmission facility.³⁶⁸¹

1746. Other commenters suggest that the Commission could improve the proposed reforms to interregional transmission coordination by requiring additional information sharing. For example, U.S. DOE recommends that the Commission require neighboring transmission planning regions to share information with one another about their geographic zones.³⁶⁸² California Energy Commission recommends that transmission providers be required to share with neighboring transmission planning regions how other planning processes, such as integrated resource plans, resource adequacy, and state requirements, are considered in regional transmission planning.³⁶⁸³ State Agencies suggest that transmission providers should provide an annual report to the Commission on their interregional transmission coordination activities, including the number of interregional transmission projects identified, the results of the cost/benefit evaluation overall and to each transmission planning region, whether other regions have been or should be included to maximize the value of the project, and any barriers to development of interregional transmission projects.³⁶⁸⁴ NARUC urges the Commission to encourage additional coordination and information sharing between non-RTO/ISO transmission planning regions like NorthernGrid and WestConnect.³⁶⁸⁵

1747. Pattern Energy asserts that the Commission should require neighboring transmission planning regions to hold forums for stakeholders to discuss right-

³⁶⁷⁷ *Id.* P 429.

³⁶⁷⁸ Acadia Center and CLF Initial Comments at 23–24; ACEG Initial Comments at 74; Ameren Initial Comments at 47; Arizona Commission Initial Comments at 10; BP Initial Comments at 13–14; Breakthrough Energy Initial Comments at 2; California Commission Initial Comments at 118–121; California Energy Commission Initial Comments at 4; California Water Initial Comments at 20–21; Clean Energy Associations Initial Comments at 40–42; EEI Initial Comments at 48; Enel Initial Comments at 4–5; Eversource Initial Comments at 55–56; Exelon Initial Comments at 60–61; Grid United Initial Comments at 7–9; Idaho Power Initial Comments at 13; Indiana Commission Initial Comments at 7–9; Interwest Initial Comments at 18–20; MISO Initial Comments at 88–89; NARUC Initial Comments at 67–70; National and State Conservation Organizations Initial Comments at 1–2; Northwest and Intermountain Initial Comments at 10, 22; OMS Initial Comments at 18–20; Pennsylvania Commission Initial Comments at 23–25; Pine Gate Initial Comments at 50–51; PIOs Initial Comments at 75–79; PJM Initial Comments at 9–10, 123–125; R Street Initial Comments at 4–5; State Agencies Initial Comments at 22–23; State Officials Supplemental Comments at 1 (citing U.S. Climate Alliance Initial Comments at 3); U.S. Climate Alliance Initial Comments at 3; U.S. DOE Initial Comments at 38–40; U.S. DOJ and FTC Initial Comments at 19–20.

³⁶⁷⁴ NOPR, 179 FERC ¶ 61,028 at P 426.

³⁶⁷⁵ *Id.* P 427.

³⁶⁷⁶ *Id.* P 428.

³⁶⁷⁹ EEI Initial Comments at 48.

³⁶⁸⁰ Idaho Power Initial Comments at 13.

³⁶⁸¹ Pennsylvania Commission Initial Comments at 24–25.

³⁶⁸² U.S. DOE Initial Comments at 18–20.

³⁶⁸³ California Energy Commission Initial Comments at 4.

³⁶⁸⁴ State Agencies Initial Comments at 23.

³⁶⁸⁵ NARUC Initial Comments at 69–70.

sizing or expanding proposed regional transmission facilities in consideration of the needs of both regions.³⁶⁸⁶ Further, Pattern Energy argues that if no interregional transmission facilities are approved in a Long-Term Regional Transmission Planning cycle, the Commission should require transmission planning regions to provide transparent reasoning to help stakeholders and regulators understand whether interregional transmission coordination requires reform.³⁶⁸⁷

1748. MISO asserts that the Commission should institute a separate and longer compliance period for the interregional transmission coordination requirements than for the regional transmission planning requirements proposed in this rulemaking.³⁶⁸⁸ Further, to reduce the compliance burden on transmission providers, MISO requests that the Commission include all interregional transmission coordination and planning requirements in a single rulemaking rather than require interregional compliance in multiple, separate proceedings.³⁶⁸⁹

1749. Many commenters assert that the Commission's proposals with respect to interregional transmission coordination do not go far enough.³⁶⁹⁰ Several commenters urge the Commission to require holistic interregional transmission planning and cost allocation.³⁶⁹¹ Some commenters encourage the Commission to require a

minimum amount of Interregional Transfer Capability between neighboring transmission planning regions.³⁶⁹² Several commenters urge the Commission to require neighboring transmission planning regions to adopt a common system model and planning assumptions, common Long-Term Scenarios, and consistent data inputs.³⁶⁹³ AEP argues that the Commission should require consistency across transmission planning regions in terms of the transmission planning horizon, planning frequency, and minimum set of benefits considered.³⁶⁹⁴

1750. MISO encourages the Commission to examine interregional transmission planning, including analysis of the assumptions related to transfer capacity and the effectiveness of collaboration between RTO and non-RTO neighbors, in a separate docket.³⁶⁹⁵ Eversource and State Agencies suggest that the Commission encourage RTOs/ISOs to increase staffing to address interregional transmission planning.³⁶⁹⁶ National Grid suggests that the Commission provide appropriate rate incentives for interregional transmission facilities.³⁶⁹⁷ Rail Electrification urges the Commission to support the siting of large interregional transmission facilities along available interstate transportation rights-of-way to advance the grid of the future more quickly.³⁶⁹⁸

C. Commission Determination

1751. We adopt, with modification, the NOPR proposal to require transmission providers in each transmission planning region to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms adopted in this final order. Specifically, we adopt the NOPR proposal to require transmission providers in neighboring transmission planning regions to revise their existing interregional transmission coordination procedures (and regional transmission

planning processes, as needed) to provide for: (1) the sharing of information regarding their respective Long-Term Transmission Needs, as well as Long-Term Regional Transmission Facilities to meet those needs; and (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address Long-Term Transmission Needs.

1752. Additionally, we adopt the NOPR proposal to require transmission providers in neighboring transmission planning regions to revise their interregional transmission coordination procedures (and regional transmission planning processes, as needed) to allow an entity to propose an interregional transmission facility in the regional transmission planning process as a potential solution to Long-Term Transmission Needs. We find that this requirement will align the existing requirement, for an entity to propose an interregional transmission facility in the regional transmission planning processes of each of the neighboring transmission planning regions in which the transmission facility is proposed to be located, with the new requirement in this final order for transmission providers to conduct Long-Term Regional Transmission Planning as part of their regional transmission planning processes.

1753. In response to commenter requests for additional information sharing and transparency of the interregional transmission coordination process, we find that additional transparency as applied to Long-Term Regional Transmission Planning is warranted.³⁶⁹⁹ Order No. 1000 requires that transmission providers in neighboring transmission planning regions maintain a website or email list for the communication of information related to interregional transmission coordination procedures.³⁷⁰⁰ We modify the NOPR proposal, and require transmission providers in each transmission planning region to provide the following additional information concerning Long-Term Regional Transmission Planning on their public website or through the email list used for communication of information related to interregional transmission coordination procedures: (1) the Long-Term Transmission Needs discussed in the interregional transmission coordination meetings; (2) any

³⁶⁸⁶ Pattern Energy Reply Comments at 14.

³⁶⁸⁷ *Id.* at 14–15.

³⁶⁸⁸ MISO Initial Comments at 89.

³⁶⁸⁹ *Id.* at 88–89.

³⁶⁹⁰ *See, e.g.*, ACEG Initial Comments at 76–78; Breakthrough Energy Initial Comments at 2; Clean Energy Associations Initial Comments at 41–42; Enel Initial Comments at 4–5; Evergreen Action Initial Comments at 5–6; Eversource Initial Comments at 56; Grid United Initial Comments at 7–8; Indiana Commission Initial Comments at 9; Interwest Initial Comments at 18–19; Invenergy Reply Comments at 18; National Grid Initial Comments at 20; OMS Initial Comments at 18; Pattern Energy Reply Comments at 12–15; Pine Gate Initial Comments at 50–51; PIOs Initial Comments at 75–77; PJM Initial Comments at 9–10, 123–124; Rail Electrification Initial Comments at 2, 8–11; RMI Initial Comments at 1–2; State Agencies Initial Comments at 23; Transmission Dependent Utilities Initial Comments at 6–7; U.S. DOE Initial Comments at 38–39; Xcel Initial Comments at 17.

³⁶⁹¹ *See, e.g.*, ACEG Initial Comments at 76–78; Clean Energy Associations Initial Comments at 41–42; Enel Initial Comments at 4–5; Evergreen Action Initial Comments at 5–6; Grid United Initial Comments at 7–8; Indiana Commission Initial Comments at 9; Interwest Initial Comments at 18–19; Invenergy Reply Comments at 18; National Grid Initial Comments at 20; OMS Initial Comments at 18; Pattern Energy Reply Comments at 12–15; Pine Gate Initial Comments at 50–51; PIOs Initial Comments at 75–77; PJM Initial Comments at 9–10, 123–124; Rail Electrification Initial Comments at 2, 8–11; RMI Initial Comments at 1–2; Shell Reply Comments at 8–9; U.S. DOE Initial Comments at 38–39; Xcel Initial Comments at 17.

³⁶⁹² *See, e.g.*, ACEG Initial Comments at 70–76; AEP Initial Comments at 17–18; Breakthrough Energy Initial Comments at 2; Evergreen Action Initial Comments at 5–6; Eversource Initial Comments at 55–56; Interwest Initial Comments at 18–20; Invenergy Initial Comments at 20–27; Invenergy Reply Comments at 19–22; Kansas Commission Initial Comments at 4–10; PJM Initial Comments at 9–10, 123–125.

³⁶⁹³ Hannon Armstrong Reply Comments at 1; Invenergy Reply Comments at 19–22; National Grid Initial Comments at 19–20; Transmission Dependent Utilities Initial Comments at 6–7; U.S. DOE Initial Comments at 18–21.

³⁶⁹⁴ AEP Reply Comments at 3–5.

³⁶⁹⁵ MISO Reply Comments at 29–30.

³⁶⁹⁶ Eversource Initial Comments at 55–56; State Agencies Initial Comments at 23.

³⁶⁹⁷ National Grid Initial Comments at 20.

³⁶⁹⁸ Rail Electrification Initial Comments at 8–12.

³⁶⁹⁹ *See, e.g.*, California Energy Commission Initial Comments at 4; NARUC Initial Comments at 69–70; Pattern Energy Reply Comments at 14–15; State Agencies Initial Comments at 23.

³⁷⁰⁰ Order No. 1000, 136 FERC ¶61,051 at PP 345, 458.

interregional transmission facilities proposed or identified in response to Long-Term Transmission Needs; (3) the voltage level, estimated cost, and estimated in-service date of the interregional transmission facilities proposed or identified as part of Long-Term Regional Transmission Planning; (4) the results of any cost-benefit evaluation of such interregional transmission facilities, with such results including both any overall benefits identified (which may occur across multiple transmission planning regions), as well as any benefits particular to each transmission planning region; and (5) the interregional transmission facilities, if any, selected to meet Long-Term Transmission Needs. We find that this modification will enhance transparency and facilitate stakeholder engagement in the interregional transmission coordination procedures as applied to Long-Term Regional Transmission Planning, thereby ensuring just and reasonable rates. We believe that this requirement to make this information publicly available will not create a significant burden because transmission providers will already share or develop such information with the transmission providers in neighboring transmission planning regions to comply with the requirement in this final order to revise their existing interregional transmission coordination procedures to reflect the Long-Term Regional Transmission Planning reforms.

1754. Taken together, we find that these reforms will ensure that Long-Term Transmission Needs identified through Long-Term Regional Transmission Planning can be considered in existing interregional transmission coordination and cost allocation processes. Further, doing so will ensure that there is an opportunity for the transmission providers in neighboring transmission planning regions to consider whether there are interregional transmission facilities that could more efficiently or cost-effectively address the identified Long-Term Transmission Needs, in turn helping to ensure just and reasonable Commission-jurisdictional rates.

1755. We decline to require the transmission providers in neighboring transmission planning regions to hold forums for stakeholders to discuss right-sizing or expanding proposed regional transmission facilities in consideration of the transmission needs of both regions, as requested by Pattern Energy. The Commission did not propose such a reform in the NOPR, and we decline to require it here.

1756. Regarding Idaho Power's request that the Commission provide transmission providers with flexibility in the methods used to determine the benefits of interregional transmission facilities, we note that this issue is addressed above in the Evaluation of the Benefits of Regional Transmission Facilities section of this final order.³⁷⁰¹ Regarding Pennsylvania Commission's comment that its support for the interregional transmission coordination reforms proposed in the NOPR are conditioned on the Commission maintaining flexibility for transmission providers to define criteria for considering and selecting transmission facilities, we note that the requirements regarding selection criteria are addressed in the section above on the Evaluation and Selection of Long-Term Regional Transmission Facilities.³⁷⁰²

1757. Regarding MISO's request for a longer compliance period for transmission providers to comply with the interregional transmission coordination requirements of this final order, we address MISO's request in the Compliance section below.³⁷⁰³

1758. With respect to commenter requests for the Commission to: (1) require holistic interregional transmission planning and cost allocation; (2) require a minimum amount of Interregional Transfer Capability between neighboring transmission planning regions; (3) require neighboring transmission planning regions to adopt a common system model, consistent data inputs, and a uniform transmission planning horizon and transmission planning frequency; (4) encourage RTOs/ISOs to increase staffing to address interregional transmission planning; (5) adopt new rate incentives for interregional transmission facilities; and (6) support the siting of large interregional transmission facilities along available transportation rights-of-way, we find such requests to be outside the scope of this proceeding. We recognize that one or more of these reforms hold the potential to enhance system reliability or provide significant consumer benefits. However, the Commission did not propose such reforms in the NOPR, and we decline to adopt them in the final order. However, we note that the Commission currently has an open proceeding in Docket No. AD23-3-000 to consider whether and how to establish a minimum requirement for

Interregional Transfer Capability, and may consider further reforms in other proceedings, as appropriate.³⁷⁰⁴

XI. Compliance Procedures

A. NOPR Proposal

1759. In the NOPR, the Commission proposed to require each transmission provider to submit a compliance filing within eight months of the effective date of any final order in this proceeding revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements adopted in any final order in this proceeding.³⁷⁰⁵ The Commission proposed that transmission providers that are not public utilities would have to adopt the requirements adopted in any final order in this proceeding as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.³⁷⁰⁶

1760. Additionally, in the NOPR, the Commission proposed to require transmission providers to demonstrate on compliance that proposed variations from the requirements in the final order are consistent with or superior to the final order.³⁷⁰⁷

B. Comments

1761. Several commenters support a compliance period of eight months or more to allow stakeholders, including Relevant State Entities, sufficient time to negotiate and agree on proposals to comply with this rulemaking.³⁷⁰⁸ PJM states that while an eight-month period to submit compliance filings is reasonable, the Commission should thereafter allow time for transmission planners to develop the tools and hire the employees they will need to implement the final order.³⁷⁰⁹ NEPOOL states that the Commission should be flexible in considering requests for extensions of time.³⁷¹⁰ Pacific Northwest State Agencies urge the

³⁷⁰⁴ See Supplemental Notice of Staff-Led Workshop, *Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Docket No. AD23-3-000 (Nov. 30, 2022).

³⁷⁰⁵ NOPR, 179 FERC ¶ 61,028 at P 430.

³⁷⁰⁶ *Id.* P 432 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63).

³⁷⁰⁷ *Id.* PP 74-75, 105, 229.

³⁷⁰⁸ Idaho Power Initial Comments at 14; ISO-NE Initial Comments at 41; MISO Initial Comments at 90; NARUC Initial Comments at 50-51; NEPOOL Initial Comments at 10; NESCOE Reply Comments at 9 (citing ISO-NE Initial Comments at 41); North Carolina Commission and Staff Initial Comments at 17; Northwest and Intermountain Initial Comments at 22-23; Pacific Northwest State Agencies Initial Comments at 28; PJM Initial Comments at 10, 129.

³⁷⁰⁹ PJM Initial Comments at 10, 129.

³⁷¹⁰ NEPOOL Initial Comments at 10.

³⁷⁰¹ See *supra* Evaluation of the Benefits of Regional Transmission Facilities section.

³⁷⁰² See *supra* Evaluation and Selection of Long-Term Regional Transmission Facilities section.

³⁷⁰³ See *infra* Compliance Procedures section.

Commission to provide flexibility rather than a rigid time period of eight months to comply with the final order.³⁷¹¹

1762. Certain TDUs argue that the Commission should require transmission providers to submit compliance filings no later than 270 days after the final order becomes effective to reflect the requirements to include an *ex ante* Long-Term Regional Transmission Cost Allocation Method, define benefits, and identify the method by which benefits are selected.³⁷¹²

1763. Some commenters request that the Commission provide longer than eight months to comply with the final order. For example, NARUC argues that eight months is unlikely to allow sufficient time for Relevant State Entities to meaningfully engage.³⁷¹³ Given the complexity of the proposals and the need to coordinate with stakeholders, Idaho Power and ISO-NE propose that the Commission allow at least one year for transmission providers to comply with the final order.³⁷¹⁴ For similar reasons, MISO urges the Commission to provide a compliance period of at least 18 months. In addition, to avoid interfering with ongoing transmission expansion efforts in some transmission planning regions, MISO argues that the Commission should allow such regions to propose their own compliance date or instead should state that the final order would not apply to any such ongoing transmission expansion efforts, including MISO's Long-Range Transmission Planning initiative.³⁷¹⁵ Additionally, MISO requests that the new order and tariff revisions complying with the final order be made effective upon the Commission's acceptance of the filing party's compliance filing.³⁷¹⁶

1764. PJM states that it would be more efficient and less confusing if PJM could first build the long-term model and then comply with the selection and cost allocation requirements at a later date. PJM therefore requests that the Commission clarify whether it is necessary for transmission providers to develop compliance procedures with respect to selection and cost allocation of transmission projects to be selected through Long-Term Regional Transmission Planning before they have had a chance to create and finalize their

long-term transmission planning processes.³⁷¹⁷

1765. MISO asserts that the Commission should allow a separate and longer compliance period for the interregional transmission coordination requirements.³⁷¹⁸

1766. Separately, MISO states that while the NOPR indicates that the Commission might permit regional flexibility in some areas, it adopts the "consistent with or superior to" legal standard for evaluating proposed deviations on compliance.³⁷¹⁹ MISO argues that this standard is too inflexible to achieve the Commission's objectives because it neither recognizes the independent nature of RTOs/ISOs nor has a built-in mechanism to acknowledge legitimate regional differences.³⁷²⁰ Therefore, MISO recommends that the Commission instead apply a version of the "independent entity" variation standard to RTOs/ISOs or otherwise make clear that the proposed reforms contemplate regional flexibility to allow RTOs to retain their best transmission planning practices, particularly those RTOs that are "early movers" of the types of reforms in the NOPR.³⁷²¹ If the Commission decides not to adopt the independent entity variation standard for this final order, MISO urges the Commission to clarify that it will recognize as "consistent with or superior to" any existing regional transmission planning processes that are substantially equivalent to the proposed requirements to avoid impeding progress already made, while compelling reform in transmission planning regions where needed.³⁷²²

1767. ISO-NE and ISO RTO Council argue that flexibility should extend to determining the rules for inclusion in the tariff, with implementation details in planning procedures or guides,

consistent with the Commission's "rule of reason" standard.³⁷²³

C. Commission Determination

1768. We adopt the NOPR proposal, with modification, and require each transmission provider to submit a compliance filing within ten months of the effective date of this final order revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets all of the requirements adopted in this final order, except those adopted in the Interregional Transmission Coordination section of this final order. In response to comments from NARUC, Idaho Power, ISO-NE, and MISO requesting a longer compliance timeline, we find that requiring a ten-month compliance period instead of the eight-month compliance period proposed in the NOPR will allow transmission providers to fully develop proposals to comply with this final order and allow stakeholders, including Relevant State Entities, to meaningfully engage in the process of developing such proposals. As discussed in the Implementation of Long-Term Regional Transmission Planning section, we require transmission providers in each transmission planning region to propose on compliance a date, no later than one year from the date on which initial filings to comply with this final order are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles). Therefore, transmission providers in each transmission planning region must propose an effective date for the OATT revisions necessary to comply with this final order that is no later than the date on which they will commence the first Long-Term Regional Transmission Planning cycle. However, transmission providers may propose an earlier effective date for some or all parts of their revised OATTs to allow them to begin implementing any aspects of the required reforms sooner than the one-year deadline to commence the first Long-Term Regional Transmission Planning cycle.

1769. We deny PJM's request for clarification to allow a later compliance deadline for the selection and cost allocation requirements of this final order and find it appropriate to require

³⁷¹¹ Pacific Northwest State Agencies Initial Comments at 28.

³⁷¹² Certain TDUs Initial Comments at 16.

³⁷¹³ NARUC Initial Comments at 50–51.

³⁷¹⁴ Idaho Power Initial Comments at 14; ISO-NE Initial Comments at 41.

³⁷¹⁵ MISO Initial Comments at 90–92.

³⁷¹⁶ *Id.* at 90–91; MISO Reply Comments at 32.

³⁷¹⁷ PJM Initial Comments at 98–104.

³⁷¹⁸ MISO Initial Comments at 89.

³⁷¹⁹ MISO Reply Comments at 4 (citing NOPR, 179 FERC ¶ 61,028 at PP 74–75).

³⁷²⁰ MISO Initial Comments at 21–22; MISO Reply Comments at 5.

³⁷²¹ MISO Reply Comments at 4. For example, MISO states that its MVP and Long-Range Transmission Plan processes are broadly consistent with the principles and goals of the NOPR and some of its specific proposals, including development of multiple futures, review of various benefit metrics, and use of a 20-year transmission planning horizon. MISO states that repeating the extensive stakeholder effort involved in developing these processes to comply with the new requirements would stall its momentum. MISO Initial Comments at 10.

³⁷²² MISO Initial Comments at 25; MISO Reply Comments at 8–9.

³⁷²³ ISO-NE Initial Comments at 20; ISO/RTO Council Initial Comments at 8–9 (citing *City of Cleveland v. FERC*, 773 F.2d. at 1376).

that transmission providers submit a compliance filing that addresses all the requirements of this final order within ten months of the effective date of this final order, with the exception of the requirements related to interregional transmission coordination, as previously noted.

1770. In response to MISO's request for a separate, longer compliance timeline for the interregional transmission coordination requirements, we also modify the NOPR proposal and require each transmission provider to submit a separate compliance filing within 12 months of the effective date of this final order revising its OATT and other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the interregional transmission coordination requirements adopted in this final order.³⁷²⁴ We find that the additional time to comply with the interregional transmission coordination requirements will allow transmission providers to coordinate with the transmission providers in each of their neighboring transmission planning regions to develop interregional transmission coordination proposals.

1771. Additionally, we adopt the proposed requirement that transmission providers that are not public utilities must adopt the requirements of this final order as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.³⁷²⁵

1772. In this final order, we make no changes to the standards used to judge requested variations, as described in Order Nos. 888, 2000, 890, and 1000.³⁷²⁶ Accordingly, we decline to grant MISO's request that the Commission apply the independent entity variation standard, rather than the "consistent with or superior to" standard, for proposed deviations from the requirements in this final order on compliance. Consistent with the Commission's findings in Order No. 890, we will continue to apply the "consistent with or superior to" standard in the context of transmission planning.³⁷²⁷

1773. Regarding MISO's request for clarification, we decline to clarify as

part of this final order that any existing transmission planning processes are consistent with or superior to the requirements in this final order. Rather, it is more appropriate for a transmission provider to submit such a request as part of its compliance filing, in which the transmission provider must demonstrate that any deviation from the requirements of this final order, including any existing processes and/or OATT provisions, are consistent with or superior to the requirements of this final order. Similarly, to the extent that a transmission provider believes that it already complies with any of the requirements of this final order, it should describe in its compliance filing how the relevant requirements are satisfied, including by referencing specific tariff sheets already on file with the Commission.

1774. In response to ISO-NE's and ISO RTO Council's comment that the final order should provide flexibility as to which implementation details should be included in planning procedures or guides consistent with the Commission's "rule of reason" standard, we note that the Commission has broad discretion in applying the rule of reason policy.³⁷²⁸ under which provisions that "significantly affect rates, terms, and conditions" of service, are realistically susceptible of specification, and are not generally understood in a contractual agreement, must be included in the tariff. The tariff need not include "mere implementation details,"³⁷²⁹ which instead may be included only in the business practice manuals. "[E]ven specifiable practices that significantly affect rates need not be included if they are clearly implied by the tariff's express terms."³⁷³⁰ The final order specifies with respect to each requirement the information that must be incorporated into the transmission provider's OATT. We find that the requirements in this final order regarding what information transmission providers must specify in their tariff on compliance is consistent with the Commission's rule of reason policy.

XII. Information Collection Statement

1775. The information collection requirements contained in this final

order are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.³⁷³¹ OMB's regulations require approval of certain information collection requirements imposed by agency rules.³⁷³² Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this final order will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

1776. The reforms adopted in this final order revise the Commission's *pro forma* OATT to remedy deficiencies in the Commission's existing regional transmission planning and cost allocation and local transmission planning requirements to ensure that Commission-jurisdictional rates and practices are just and reasonable and not unduly discriminatory or preferential.

1777. In the NOPR, the Commission solicited comments on: the Commission's need for this information; whether the information will have practical utility; the accuracy of the burden estimates; ways to enhance the quality, utility, and clarity of the information to be collected or retained; and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. The Commission received one comment from PJM specifically about the time and effort required to comply with the information collection requirement.³⁷³³

1778. PJM claims that the Commission significantly underestimates the cost for PJM and other transmission providers to comply with the final order. PJM states that its compliance will require additional staff of between seven to 14 new staff members and that the added cost will be at least \$2.1 million per year. However, PJM adds that it generally supports the proposed reforms in the NOPR and provides this information only to give the Commission a better understanding of the time and costs associated with implementing the final order.³⁷³⁴

1779. In response to PJM's comments on the NOPR, we note that this information collection statement estimates the burdens³⁷³⁵ to generate,

³⁷²⁴ See *supra* Interregional Transmission Coordination section.

³⁷²⁵ NOPR, 179 FERC ¶ 61,028 at P 432 (citing Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63).

³⁷²⁶ Order No. 1000, 136 FERC ¶ 61,051 at P 815; Order No. 890, 118 FERC ¶ 61,119 at P 109; Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,164; Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,769–70.

³⁷²⁷ Order No. 890, 118 FERC ¶ 61,119 at P 160.

³⁷²⁸ *Hecate Energy Greene Cnty. 3 LLC v. FERC*, 72 F.4th at 1314 (citing *City of Cleveland v. FERC*, 773 F.2d at 1376 (the FPA's "amorphous" requirement that tariffs include "practices affecting rates" means that the Commission has "broad discretion" in giving the act "concrete application.")).

³⁷²⁹ *Id.* at 1312.

³⁷³⁰ *Id.* at 1314 (citing *City of Cleveland v. FERC*, 773 F.2d at 1376).

³⁷³¹ 44 U.S.C. 3507(d).

³⁷³² 5 CFR 1320.11.

³⁷³³ PJM Initial Comments at 10, 125–29.

³⁷³⁴ *Id.* at 128–29.

³⁷³⁵ "Burden" is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation

maintain, retain, or disclose or provide information to or for a Federal agency. In light of the information that PJM supplied, we have revised the table below to increase the estimated amount of labor required for a transmission provider to perform Long-Term Regional Transmission Planning.³⁷³⁶ We expect that the information collection requirements associated with updating these datasets for subsequent cycles will entail substantially less effort than the initial Long-Term Regional Transmission Planning cycle.

1780. Summary of the Revisions to the Collection of Information due to the final order in Docket No. RM21–17–000:

- *Title:* Electric Transmission Facilities (FERC–917).³⁷³⁷
- *Action:* Revision of collections of information in accordance with Docket No. RM21–17–000.
- *OMB Control Nos.:* 1902–0233 (FERC–917).
- *Respondents:* Transmission providers, including RTOs/ISOs.

- *Frequency of Information Collection:* One time during Year 1. Occasional times during subsequent years, at least once every five years.

- *Necessity of Information:* The reforms in this final order will correct deficiencies in the Commission's existing regional transmission planning and cost allocation requirements to ensure that Commission-jurisdictional rates remain just and reasonable and not unduly discriminatory or preferential.

- *Internal Review:* We have reviewed the reforms and have determined that such reforms are necessary. These reforms conform to the Commission's need for efficient information collection, communication, and management within the energy industry. We have specific, objective support for the burden estimates associated with the information collection requirements.

- *Public Reporting Burden:* The burden and cost estimates below are based on the need for applicable entities

to revise documentation, already required by the Commission's *pro forma* OATT. Our estimates are based on the North American Electric Reliability Corporation Compliance Registry as of January 11, 2024, which indicates that there are 48 transmission service providers³⁷³⁸ with OATTs and 118 transmission owners that are registered within the United States and are subject to this rulemaking.³⁷³⁹ Because 41 of the 118 transmission owners are also included in the count of 48 transmission service providers, there are 125 distinct entities (*i.e.*, 125 distinct transmission providers^{3740 3741 3742}) in total that must comply this final order. We note that, for the purposes of regional transmission planning, these 125 entities are grouped into 11 transmission planning regions.

1781. We estimate that the final order would affect the burden and cost of FERC–917 as follows:

CHANGES DUE TO FINAL ORDER IN DOCKET NO. RM21–17–000³⁷⁴¹

Area of modification	Annual number of respondents	Total annual estimated number of responses	Average burden hours & cost ³⁷⁴² per response	total estimated burden hours & total estimated cost (column C × column D)
A	B	C	D	E
FERC–917, Electric Transmission Facilities (OMB Control No. 1902–0233)				
Draft OATT revisions to comply with the requirements of the final order.	48 transmission providers with OATTs.	48	One Time: 770 hours; \$71,683. Ongoing: 0 hours per year; \$0 per year.	One Time: 36,960 hours; \$3,440,783. Ongoing: 0 hours per year; \$0 per year.
Establish a six-month time period during which transmission providers must, among other things, provide a forum for negotiation that enables participation by Relevant State Entities and to discuss potential Long-Term Regional Transmission Cost Allocation Methods and/or a State Agreement Process.	48 transmission providers with OATTs.	48	One Time: 390 hours; \$36,307. Ongoing: 0 hours per year; \$0 per year.	One Time: 18,720 hours; \$1,742,734. Ongoing: 0 hours per year; \$0 per year.

of what is included in the information collection burden, refer to 5 CFR 1320.3(b)(1).

³⁷³⁶ For example, for an entire transmission planning region, we anticipate that 10 people each working 2,000 hours per year would spend 20,000 hours per year to develop these datasets.

³⁷³⁷ In the NOPR, in addition to proposing to revise the FERC–917 information collection, the Commission proposed to revise the *pro forma* LGIP and, therefore, to revise the FERC–516 information collection (Reform of Generator Interconnection Procedures and Agreements). In this final order, we decline to revise the *pro forma* LGIP, and therefore we are not revising the FERC–516 information collection.

³⁷³⁸ The transmission service provider (TSP) function is a North American Electric Reliability

Corporation registration function, which is similar to the transmission provider that is referenced in the *pro forma* OATT. The TSP function is being used as a proxy to estimate the number of transmission providers that are impacted by this proposed rulemaking.

³⁷³⁹ The number of entities listed from the North American Electric Reliability Corporation Compliance Registry reflects the omission of the Texas registered entities. Note that the 48 transmission providers with OATTs do not include non-public utility transmission providers with reciprocity tariffs.

³⁷⁴⁰ See *supra* note 2.

³⁷⁴¹ In the table, Year 1 figures are one-time implementation hours and cost. "Subsequent years" show ongoing burdens and costs starting in Year 2.

³⁷⁴² The hourly cost (for salary plus benefits) uses the figures from the Bureau of Labor Statistics (BLS) for three positions involved in the reporting and recordkeeping requirements. These figures include salary (based on BLS data for May 2022, issued April 25, 2023, http://bls.gov/oes/current/naics2_22.htm) and benefits (based on BLS data for September 2023; issued December 15, 2023, <http://www.bls.gov/news.release/cec.nr0.htm>) and are Manager (Occupation Code 11–0000, \$122.48/hour), Electrical Engineer (Occupation Code 17–2071, \$89.04/hour), and File Clerk (Occupation Code 43–4071, \$42.43/hour). The hourly cost for the reporting requirements (\$105.76) is an average of the hourly cost (wages plus benefits) of a manager and engineer. The hourly cost for recordkeeping requirements uses the cost of a file clerk.

CHANGES DUE TO FINAL ORDER IN DOCKET NO. RM21-17-000³⁷⁴¹—Continued

Area of modification	Annual number of respondents	Total annual estimated number of responses	Average burden hours & cost ³⁷⁴² per response	total estimated burden hours & total estimated cost (column C × column D)
A	B	C	D	E
Participate in Long-Term Regional Transmission Planning, which includes creating and updating datasets, developing Long-Term Scenarios, evaluating the benefits of Long-Term Regional Transmission Facilities, and establishing criteria in consultation with Relevant State Entities and stakeholders to select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation.	48 transmission providers with OATTs.	48	One Time: 0 hours; \$0. Ongoing: 4,500 hours per year; \$418,926 per year.	One Time: 0 hours; \$0. Ongoing: 216,000 hours per year; \$20,108,471 per year.
	77 transmission providers without OATTs.	77	One Time: 0 hours; \$0. Ongoing: 200 hours per year; \$18,619.	One Time: 0 hours; \$0. Ongoing: 15,400 hours per year; \$1,433,659 per year.
Revise the regional transmission planning process to enhance transparency of local transmission planning and identifying potential opportunities to right-size replacement transmission facilities.	48 transmission providers with OATTs.	48	One Time: 30 hours; \$2,793. Ongoing: 120 hours per year; \$11,172 per year.	One Time: 1,440 hours; \$134,056. Ongoing: 5,760 hours per year; \$536,226 per year.
	77 transmission providers without OATTs.	77	One Time: 20 hours; \$1,862. Ongoing: 40 hours per year; \$3,724 per year.	One Time: 1,540 hours; \$143,366. Ongoing: 3,080 hours per year; \$286,732 per year.
Evaluate whether certain alternative transmission technologies can meet the transmission needs identified in Order No. 1000 regional transmission planning processes and in Long-Term Regional Transmission Planning process more efficiently or cost-effectively than transmission facilities without such alternative transmission technologies.	48 transmission providers with OATTs.	48	One Time: 0 hours; \$0. Ongoing: 100 hours per year; \$9,309 per year.	One Time: 0 hours; \$0. Ongoing: 4,800 hours per year; \$446,855 per year.
	77 transmission providers without OATTs.	77	One Time: 0 hours; \$0. Ongoing: 20 hours per year; \$1,862 per year.	One Time: 0 hours; \$0. Ongoing: 1540 hours per year; \$143,366 per year.
Consider in the Order No. 1000 regional transmission planning processes regional transmission facilities that address certain interconnection-related needs..	48 transmission providers with OATTs.	48	One Time: 0 hours; \$0. Ongoing: 50 hours per year; \$4,655 per year.	One Time: 0 hours; \$0. Ongoing: 2,400 hours per year; \$223,427 per year.
Share with the transmission providers in neighboring transmission planning regions information regarding Long-Term Transmission Needs and potential transmission facilities to meet those needs; identify and jointly evaluate interregional transmission facilities with the transmission providers in neighboring transmission planning regions; and publicly post certain information regarding interregional coordination processes applied to Long-Term Regional Transmission Planning..	48 transmission providers with OATTs.	48	One Time: 0 hours; \$0. Ongoing: 25 hours per year; \$2,327 per year.	One Time: 0 hours; \$0. Ongoing: 1,200 hours per year; \$111,714 per year.
Total burden for the revisions of FERC 917 due to RM21-17.	48 transmission providers with OATTs.	48	One Time: 1,190 hours; \$110,783. Ongoing: 4,795 hours per year; \$446,390 per year.	One Time: 57,120 hours; \$5,317,573. Ongoing: 230,160 hours per year; *\$21,426,693 per year.
1	77 transmission providers without OATTs.	77	One Time: 20 hours; \$1,862. Ongoing: 260 hours per year; \$24,205 per year.	One Time: 1,540 hours; \$143,366. Ongoing: 20,020 hours per year; \$1,863,757 per year.
Totals for all 125 transmission providers				One Time: 58,660 hours; \$5,460,939. Ongoing: 250,180 hours per year; \$23,290,450 per year.

1782. Our estimates conservatively assume the maximum number of respondents and burdens. We acknowledge that the actual burdens for some respondents may be lower than estimated and that other respondents may incur the maximum burdens.

1783. Interested persons may obtain information on the reporting requirements by contacting Jean Sonneman, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 via email (DataClearance@ferc.gov) or telephone (202) 502-8663.

XIII. Environmental Analysis

1784. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.³⁷⁴³ We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this final order under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.³⁷⁴⁴

XIV. Regulatory Flexibility Act

1785. The Regulatory Flexibility Act of 1980 (RFA)³⁷⁴⁵ generally requires a description and analysis of rulemakings that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold for what constitutes a small business. Under SBA's size standards,³⁷⁴⁶ RTOs/ISOs, transmission planning regions, and transmission owners all fall under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), with a size threshold of 950

employees (including the entity and its associates).³⁷⁴⁷

1786. We have determined that the entities impacted by this final order are transmission providers in transmission planning regions that span across the United States.³⁷⁴⁸

1787. To identify small firms among the transmission providers that comprise the transmission planning regions, we created a list of transmission service providers and transmission owners from the North American Electric Reliability Corporation Registry (dated January 11, 2024), totaling 125 entities. We conducted research using both open-source information and data from paid services such as Dunn & Bradstreet. We find that, out of the population of 125 transmission providers, 18 would be considered small using the SBA threshold (14% rounded). Therefore, we do not consider this number of small entities to be substantial.

1788. As shown in the table above, we estimate the one-time costs associated with the final order to be \$110,783 per transmission provider with an OATT and \$1,862 per transmission provider without an OATT. We estimate the ongoing costs in subsequent years to be \$446,390 per year for transmission providers with an OATT and \$24,205 per year for transmission providers without an OATT. Further, we note that Commission regulations allow for transmission providers to fully recover the costs of participating in the regional transmission planning process.³⁷⁴⁹

Therefore, we do not believe that this cost is economically significant. Accordingly, we certify that the reforms in this final order will not have a significant economic impact on a substantial number of small entities.

XV. Document Availability

1789. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the

Commission's Home Page (<https://www.ferc.gov>).

1790. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

1791. User assistance is available for eLibrary and the Commission's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. Email the Public Reference Room at public.referenceroom@ferc.gov.

XVI. Effective Date and Congressional Notification

1792. This final order is effective August 12, 2024. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this order is a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By the Commission.

Chairman Phillips and Commissioner Clements are concurring with a joint separate statement attached.

Commissioner Christie is dissenting with a separate statement attached.

Issued May 13, 2024.

Debbie-Anne A. Reese,
Acting Secretary.

Note: The following appendices will not appear in the Code of Federal Regulations.

Appendix A: Abbreviated Names of Commenters

ABBREVIATED NAMES OF COMMENTERS

Abbreviation	Commenter(s)
Acadia Center and CLF	Acadia Center and Conservation Law Foundation.

³⁷⁴³ *Regulations Implementing the Nat'l Env'l Pol'y Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

³⁷⁴⁴ 18 CFR 380.4(a)(15).

³⁷⁴⁵ 5 U.S.C. 601-612.

³⁷⁴⁶ 13 CFR 121.201.

³⁷⁴⁷ The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. The SBA's regulations define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 950

employees. 13 CFR 121.201; see 5 U.S.C. 601(3) (citing section 3 of the Small Business Act, 15 U.S.C. 632).

³⁷⁴⁸ See FERC, *Regions Map Printable Version Order No. 1000* (Nov. 9, 2021), <https://www.ferc.gov/media/regions-map-printable-version-order-no-1000>.

³⁷⁴⁹ Order No. 890, 118 FERC ¶ 61,119 at P 586.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
ACEG	Americans for a Clean Energy Grid.
ACORE	American Council on Renewable Energy.
Advanced Energy Buyers	Advanced Energy Buyers Group.
AEE	Advanced Energy Economy.
AEP	American Electric Power Service Corporation.
Alabama Commission	Alabama Public Service Commission.
Amazon	Amazon Energy LLC.
Ameren	Ameren Services Company.
American Municipal Power	American Municipal Power, Inc.
Americans for Fair Energy Prices	Americans for Fair Energy Prices, Inc.
Anbaric	Anbaric Development Partners, LLC.
APPA	American Public Power Association.
APS	Arizona Public Service Company.
Arizona Commission	Arizona Corporation Commission.
ATC	American Transmission Company LLC.
Avangrid	Avangrid, Inc.
Bekaert	Bekaert Corporation.
BP	bp America.
Breakthrough Energy	Breakthrough Energy.
Business Council for Sustainable Energy	Business Council for Sustainable Energy.
CAISO	California Independent System Operator Corporation.
California Commission	California Public Utilities Commission.
California Democratic Representatives	U.S. Representatives Jared Huffman; Mike Levin; Nanette Diaz Barragán; Grace F. Napoli- tano; Anna G. Eshoo; Katie Porter; Judy Chu; Mike Thompson; Ted W. Lieu; Julia Brownley; Mark DeSaulnier; and Juan Vargas.
California Energy Commission	California Energy Commission.
California Municipal Utilities	California Municipal Utilities Association.
California Water	California Department of Water Resources State Water Project.
CARE Coalition	The National Audubon Society; Defenders of Wildlife; Environmental Law & Policy Center; Na- tional Wildlife Federation; The Nature Conservancy; Center for Renewables Integration; and Vote Solar, jointly the Conservation and Renewable Energy Coalition.
Center for Biological Diversity	The Center for Biological Diversity.
Ceres	Ceres.
Certain TDUs	Alliant Energy Corporate Services, Inc.; Consumers Energy Company; and DTE Electric Com- pany.
Chemistry Council	American Chemistry Council.
Citizens Energy	Citizens Energy Corporation.
City of New Orleans Council	Council of the City of New Orleans.
City of New York	City of New York.
Clean Energy Associations	The American Clean Power Association; Alliance for Clean Energy—New York; Clean Grid Al- liance; the Mid-Atlantic Renewable Energy Council Action; and the New York Offshore Wind Alliance, collectively Clean Energy Associations.
Clean Energy Buyers	Clean Energy Buyers Association.
Clean Energy States	Clean Energy States Alliance.
Colorado Consumer Advocate	Colorado Office of the Utility Consumer Advocate.
Competition Advocates	Niskanen Center; R Street Institute; Institute for Local Self Reliance; Public Citizen, Inc.; Cen- ter for Biological Diversity; and Open Markets Institute.
Competition Coalition	Electricity Transmission Competition Coalition.
Concerned Scientists	The Union of Concerned Scientists.
Conservative Energy Network	Conservative Energy Network.
Conservatives for Clean Energy—Florida	Conservatives for Clean Energy—Florida.
Conservatives for Clean Energy—SC	Conservatives for Clean Energy—South Carolina.
Consumer Organizations	NJ Charge, Inc.; Keryn Newman (Stop Path WV); Illinois Landowners Alliance; Block Grain Belt Express—Missouri; Citizens to Stop Transource—York; Coalition for Rural Property Rights; Eastern Missouri Landowners Alliance; Missouri Landowners Association; Protect Sudbury Inc.; Say No to NECEC; Stop B2H Coalition; Eastern Missouri Landowners Alli- ance; SOUL of Wisconsin; Block RICL; Matthew Stallbaumer; Vickie Husbands; Elena Guardincerri; Martha Peine; Kerry Beheler; Barron Shaw; and STOP Transource Power Lines MD, Inc.
Cross Sector Representatives	Ameren Transmission; Blue-Green Alliance; Consolidated Edison Company of New York, Inc.; Edison International; Exelon Corporation; Greater Warren County Economic Development Council; International Brotherhood of Electric Workers IBEW 1245; IBEW Illinois State Con- ference; IBEW International; IBEW Sixth District; ITC Holdings Corp.; National Audubon So- ciety; Pacific Gas & Electric Co.; The Permitting Institute; Public Service Electric and Gas Company; WEG Transformers USA; and Xcel Energy.
CTC Global	CTC Global Corporation.
Cypress Creek	Cypress Creek Renewables, LLC.
DATA	Ameren Services Company; Eversource Energy; Exelon Corporation; ITC Holdings Corp.; Na- tional Grid USA; Public Service Electric and Gas Company; and Xcel Energy; collectively Developers Advocating Transmission Advancements (DATA).
DC and MD Offices of People's Counsel	The Office of the People's Counsel for the District of Columbia and the Maryland Office of People's Counsel.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
Dominion	Dominion Energy Services, Inc.
Duke	Duke Energy Corporation.
Duquesne Light	Duquesne Light Company.
EEL	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council.
Enel	Enel North America, Inc.
ENGIE	ENGIE North America, Inc.
Entergy	Entergy Services, LLC.
Environmental Groups	Advanced Energy United; American Clean Power Association; Clean Air Task Force; EarthJustice; Environmental Defense Fund; Evergreen Action; Fresh Energy; Interwest Energy Alliance; League of Conservation Voters; National Wildlife Federation; Natural Resources Defense Council; Northwest Energy Coalition; Rewiring America; Sierra Club; Southern Environmental Law Center; The Environmental Law & Policy Center; Union of Concerned Scientists; WE ACT for Environmental Justice; and Western Resource Advocates.
Environmental Legislators Caucus	National Caucus of Environmental Legislators.
EPSA	Electric Power Supply Association.
Evergreen Action	Evergreen Action and 4,440 Individual Signers.
Eversource	Eversource Energy Service Company.
Exelon	Exelon Corporation.
Fervo	Fervo Energy Company.
Form Energy	Form Energy, Inc.
Freeport-McMoRan	Freeport-McMoRan, Inc.
Georgia Commission	Georgia Public Service Commission.
Governor of Kansas Laura Kelly	Governor of the State of Kansas Laura Kelly.
Grand Rapids NAACP	Greater Grand Rapids Chapter of The National Association for the Advancement of Colored People.
Grid United	Grid United LLC.
GridLab	GridLab.
Handy Law	Seth Handy, Handy Law, LLC.
Hannon Armstrong	Hannon Armstrong Sustainable Infrastructure Capital, Inc.
Harvard ELI	Harvard Electricity Law Initiative.
Idaho Commission	The Idaho Public Utilities Commission.
Idaho Power	Idaho Power Company.
Illinois Commission	The Illinois Commerce Commission.
Indiana Commission	Indiana Utility Regulatory Commission.
Indicated PJM TOs	The Dayton Power and Light Company; Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company; Duke Energy Corporation on behalf of its affiliates Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Duke Energy Business Services LLC; Duquesne Light Company; East Kentucky Power Cooperative; Exelon Corporation; FirstEnergy Service Company, on behalf of its affiliates American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Mid-Atlantic Interstate Transmission LLC, West Penn Power Company, The Potomac Edison Company, Monongahela Power Company, Keystone Appalachian Transmission Company, and Trans-Allegheny Interstate Line Company; PPL Electric Utilities Corporation; Public Service Electric and Gas Company; Rockland Electric Company; and UGI Utilities Inc.
Indicated U.S. Senators and Representatives ...	U.S. Senators Tina Smith; Edward J. Markey; and Sheldon Whitehouse; U.S. Representatives Kathy Castor; Bobby L. Rush; Paul Tonko; Sean Casten; Raja Krishnamoorthi; Jared Huffman; Veronica Escobar; and Julia Brownley
Industrial Customers	American Forest & Paper Association; the PJM Industrial Customer Coalition; and the Coalition of MISO Transmission Customers, collectively the Industrial Customer Organizations.
Interwest	Interwest Energy Alliance.
Invenergy	Invenergy Solar Development North America LLC; Invenergy Thermal Development LLC; Invenergy Wind Development North America LLC; and Invenergy Transmission LLC.
Iowa Commission	Iowa Utilities Board.
ISO/RTO Council	The ISO/RTO Council.
ISO-NE	ISO New England Inc.
ITC	International Transmission Company; Michigan Electric Transmission Company, LLC; ITC Midwest LLC; and ITC Great Plains, LLC.
Joint Commenters	American Public Power Association; Electricity Consumers Resource Council; Indiana Office of Utility Consumer Counselor; Large Public Power Council; National Association of State Utility Consumer Advocates; Office of People's Counsel for the District of Columbia; Public Advocate for the State of Delaware; and Solar Energy Industries Association.
Joint Consumer Advocates	Iowa Office of Consumer Advocate and Indiana Office of Utility Consumer Counselor.
Kansas Commission	Kansas Corporation Commission.
Kansas Commission Chair Keen	Kansas Corporation Commission Chairman Dwight D. Keen.
Kansas Ratepayers Advocates	Kansas Industrial Consumers Group, Inc. and Kansans for Lower Electric Rates, Inc.
Kentucky Commission Chair Chandler	Kentucky Public Service Commission Chairman and Commissioner Kent A. Chandler.
LADWP	Los Angeles Department of Water & Power.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
Large Energy Customers	Akamai Technologies, Inc.; Amazon.com, Inc.; Amy's Kitchen, Inc.; Apple, Inc.; Applied Materials, Inc.; ARC Homes; Atlassian Corporation; Autodesk, Inc.; BASF Corporation; Best Buy Co., Inc.; Brookfield Properties; Budderfly, Inc.; Build Efficiently, LLC.; Cargill, Inc.; Clean Energy Buyers Association; Eastman Chemical Company; eBay, Inc.; Equinix, Inc.; Freeport-McMoRan, Inc.; General Motors LLC; Google LLC; Green Impact Technologies; Hewlett Packard Enterprise Company; Humanscale Corporation; IHG Hotels & Resorts; Marriott International, Inc.; Mars, Inc.; Meta Platforms, Inc.; Microsoft Corporation; Monarch Energy; Nike, Inc.; Nucor Corporation; Oatly Group AB; PepsiCo, Inc.; Prologis, Inc.; Rivian Automotive, Inc.; Saint-Gobain North America; Salesforce, Inc.; Schneider Electric SE; Target Corporation; Thermo Fisher Scientific, Inc.; The STAAC Group, LLC., Walmart, Inc.; Workday, Inc.; and World Energy, LLC.
Large Public Power	The Large Public Power Council.
Louisiana Commission	Louisiana Public Service Commission.
LS Power	LS Power Grid, LLC.
Maine Public Advocate	The Maine Office of the Public Advocate.
Maryland Energy Administration	Maryland Energy Administration.
Massachusetts Attorney General	Massachusetts Attorney General Maura Healey.
Michigan Commission	Michigan Public Service Commission.
Michigan Conservative Energy Forum	Michigan Conservative Energy Forum.
Michigan State Entities	Michigan Attorney General and the Citizens Utility Board of Michigan.
Microgrid Resources	Microgrid Resources Coalition.
Middle River Power	Middle River Power LLC.
Minnesota State Entities	The Minnesota Public Utilities Commission and The Minnesota Department of Commerce.
MISO	Midcontinent Independent System Operator, Inc.
MISO Coops	The Coalition of MISO Generation and Transmission Cooperatives.
MISO TOs	Ameren Services Company, as agent for Union Electric Company, Ameren Illinois Company, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.
Mississippi Commission	The Mississippi Public Service Commission.
Montana QF Developers	Clenera, LLC and Greenfields Irrigation District.
Montclair Congregation	40 Undersigned Congregants of Montclair Presbyterian Church.
NARUC	The National Association of Regulatory Utility Commissioners.
NASEO	The National Association of State Energy Officials.
NASUCA	The National Association of State Utility Consumer Advocates.
National and State Conservation Organizations	National Wildlife Federation; Conservation Coalition of Oklahoma; Environment Council of Rhode Island; Environmental League of Massachusetts; Idaho Wildlife Federation; Iowa Wildlife Federation; Kentucky Waterways Alliance; Natural Resources Council of Maine; Nevada Wildlife Federation; New Jersey Audubon; Southeast Alaska Conservation Council; Texas Conservation Alliance; Utah Wildlife Federation; WV Rivers Coalition; and Wyoming Wildlife Federation.
National Grid	National Grid Plc.
Nebraska Commission	The Nebraska Power Review Board.
NEMA	National Electrical Manufacturers Association.
NEPOOL	The New England Power Pool Participants Committee.
NERC	North American Electric Reliability Corporation; Midwest Reliability Organization; Northeast Power Coordinating Council, Inc.; ReliabilityFirst Corporation; SERC Reliability Corporation, Texas Reliability Entity, Inc., and Western Electricity Coordinating Council.
NESCOE	The New England States Committee on Electricity.
Nevada Commission	The Public Utilities Commission of Nevada.
New England for Offshore Wind	New England for Offshore Wind.
New England Systems	Belmont Municipal Light Department; Block Island Utility District; Braintree Electric Light Department; Chicopee Municipal Light Department; Georgetown Municipal Light Department; Hingham Municipal Lighting Plant; Littleton Electric Light & Water Department; Middleborough Gas & Electric Department; Middleton Electric Light Department; North Attleborough Electric Department; Norwood Municipal Light Department; Pascoag Utility District; Reading Municipal Light Department; Stowe Electric Department; Taunton Municipal Lighting Plant; Wallingford Electric Division; and Westfield Gas & Electric Light Department.
New Jersey Commission	The New Jersey Board of Public Utilities.
New Mexico RETA	The New Mexico Renewable Energy Transmission Authority.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
New York Commission and NYSERDA	New York Public Service Commission and New York State Energy Research and Development Authority.
New York State Department	New York State Department of State Utility Intervention Unit.
New York TOs	Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; Niagara Mohawk Power Corporation; New York Power Authority; New York State Electric & Gas Corporation; Orange and Rockland Utilities, Inc.; Long Island Power Authority; and Rochester Gas and Electric Corporation.
New York Transco	New York Transco, LLC.
NextEra	NextEra Energy, Inc.
Non-RTO NASUCA	North Carolina Utilities Commission Public Staff; the Utah Office of Consumer Service; the South Carolina Office of Regulatory Staff; and the Wyoming Office of Consumer Advocate.
North Carolina Commission and Staff	The North Carolina Utilities Commission and the North Carolina Utilities Commission Public Staff.
North Dakota Commission	North Dakota Public Service Commission Public Utilities Division.
Northwest and Intermountain	Northwest & Intermountain Power Producers Coalition.
NRECA	National Rural Electric Cooperative Association.
NRG	NRG Energy, Inc.
NYISO	New York Independent System Operator, Inc.
NYPA	New York Power Authority.
Ohio Commission Federal Advocate	The Public Utilities Commission of Ohio's Office of the Federal Energy Advocate.
Ohio Conservative Energy Forum	Ohio Conservative Energy Forum.
Ohio Consumers	Office of The Ohio Consumers' Counsel.
Omaha Public Power	The Omaha Public Power District.
OMS	The Organization of Midcontinent Independent System Operator States, Inc.
Onward Energy	Onward Energy Holdings, LLC.
Ørsted	Ørsted North America.
Pacific Northwest State Agencies	The Washington Utilities and Transportation Commission; Oregon Public Utility Commission; Washington State Department Of Commerce; and Oregon Department Of Energy.
Pacific Northwest Utilities	Avista Corporation; Portland General Electric; Puget Sound Energy, Inc.; and Tacoma Power.
PacifiCorp and NV Energy	PacifiCorp; Nevada Power Company and Sierra Pacific Power Company (together, NV Energy).
Pattern Energy	Pattern Energy Group LP.
Payton Alaama	Payton Alaama.
Pennsylvania Commission	The Pennsylvania Public Utility Commission.
PG&E	Pacific Gas and Electric Company.
Pine Gate	Pine Gate Renewables, LLC.
PIOs	Sustainable FERC Project; Natural Resources Defense Council; Sierra Club; Environmental Defense Fund; Southern Environmental Law Center; Conservation Law Foundation; Western Resource Advocates; Acadia Center; NW Energy Coalition; Southface Institute; and Fresh Energy, jointly Public Interest Organizations.
PJM	PJM Interconnection, L.L.C.
PJM Market Monitor	The Independent Market Monitor of PJM Interconnection, L.L.C.
PJM States	The Organization of PJM States, Inc. (OPSI).
Policy Integrity	The Institute for Policy Integrity at New York University School of Law.
Potomac Economics	Potomac Economics, Ltd.
PPL	PPL Electric Utilities Corporation; Louisville Gas & Electric and Kentucky Utilities (collectively LG&E/KU); and The Narragansett Electric Company.
Prysmian	The Prysmian Group.
Public Systems	Massachusetts Municipal Wholesale Electric Company; New Hampshire Electric Cooperative, Inc.; Connecticut Municipal Electric Energy Cooperative; and Vermont Public Power Supply Authority.
QCo	QCoefficient, Inc.
R Street	R Street Institute.
Rail Electrification	The Rail Electrification Council.
Renewable Northwest	Renewable Northwest.
Resale Iowa	Resale Power Group of Iowa.
RMI	RMI.
SDG&E	San Diego Gas & Electric Company.
SEIA	The Solar Energy Industries Association.
SEPA	The Smart Electric Power Alliance.
SERTP Sponsors	Associated Electric Cooperative, Inc.; Dalton Utilities; Duke Energy Carolinas, LLC and Duke Energy Progress, LLC; Georgia Transmission Corporation; Louisville Gas and Electric Company and Kentucky Utilities Company; the Municipal Electric Authority of Georgia; PowerSouth Energy Cooperative; Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, and Mississippi Power Company; the Tennessee Valley Authority; and Gulf Power Company, collectively Sponsors of the Southeastern Regional Transmission Planning Process (SERTP).
Shell	Shell Energy North America (U.S.), L.P.; Shell New Energies U.S., LLC; and Savion L.L.C.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
Signatories	American Council on Renewable Energy; Americans for a Clean Energy Grid; American Clean Power Association; AES Corporation; Advance Energy Economy; Center for Rural Affairs; Clean Air Task Force; Clean Energy Buyers Alliance; Conservative Energy Network; ConEd Transmission, Inc.; Enel North America, Inc.; Exelon Corporation; GE Renewables; Grid United LLC; Google; Holy Cross Energy; Invenergy; ITC Holdings Corp.; Land & Liberty Coalition; Macro Grid Initiative; National Audubon Society; National Electrical Manufacturer Association; National Wildlife Federation; Natural Resources Defense Council; NextEra Energy, Inc.; Northwest & Intermountain Power Producers Coalition; Pattern Energy; Rail Electrification Council; Rocky Mountain Institute (RMI); Sierra Club; Solar Energy Industries of America; and Southern Renewable Energy Association.
Six Cities	The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
Smart Wires	Smart Wires.
SoCal Edison	Southern California Edison Company.
Southeast PIOs	Southern Environmental Law Center; Energy Alabama; North Carolina Sustainable Energy Association; South Carolina Coastal Conservation League; Southface Energy Institute; and Southern Alliance for Clean Energy, jointly Southeast Public Interest Groups.
Southern	Southern Company Services, Inc.
Southwestern Power Group	Southwestern Power Group.
SPP	Southwest Power Pool Inc.
SPP Market Monitor	The Southwest Power Pool Market Monitoring Unit.
SREA	Southern Renewable Energy Association.
State Agencies	Connecticut Department of Energy and Environmental Protection; Connecticut Attorney General; Connecticut Office of Consumer Counsel; Connecticut Public Utilities Regulatory Authority; California Energy Commission; Delaware Division of the Public Advocate; Attorney General of the District of Columbia; Maine Office of the Public Advocate; Maryland Attorney General; Massachusetts Attorney General; Michigan Attorney General; Pennsylvania Office of The Consumer Advocate; and the Rhode Island Attorney General.
State of Tennessee	State of Tennessee.
State Officials	Maine Governor's Energy Office; Washington State Department of Commerce; Arizona Governor's Office of Resiliency; California Natural Resources Agency; Colorado Energy Office; Deputy Governor of Illinois; Maryland Energy Administration; Michigan Department of Environment, Great Lakes, and Energy; New Mexico Energy Minerals and Natural Resources Department; Office of New York Governor Kathy Hochul; and Office of North Carolina Governor Roy Cooper.
State Water Contractors	State Water Contractors.
Tabors Caramanis Rudkevich	Tabors Caramanis & Rudkevich.
TANC	Transmission Agency of Northern California.
TAPS	Transmission Access Policy Study Group.
Transmission Dependent Utilities	Golden Spread Electric Cooperative, Inc.; North Carolina Electric Membership Corporation; and Seminole Electric Cooperative, Inc., collectively, Transmission Dependent Utility Systems.
Transource	Transource Energy, LLC.
Undersigned States [Initial Comments]	Utah Attorney General; Alaska Attorney General; Georgia Attorney General; Idaho Attorney General; Indiana Attorney General; Kansas Attorney General; Kentucky Attorney General; Louisiana Attorney General; Mississippi Attorney General; Montana Attorney General; Nebraska Attorney General; North Dakota Attorney General; Ohio Attorney General; Oklahoma Attorney General; South Carolina Attorney General; Texas Attorney General; West Virginia Attorney General; and Wyoming Attorney General.
Undersigned States [Reply Comments]	Utah Attorney General; Alabama Attorney General; Alaska Attorney General; Arkansas Attorney General; Florida Attorney General; Georgia Attorney General; Kansas Attorney General; Kentucky Attorney General; Louisiana Attorney General; Mississippi Attorney General; Montana Attorney General; Nebraska Attorney General; Ohio Attorney General; Oklahoma Attorney General; South Carolina Attorney General; Texas Attorney General; and West Virginia Attorney General.
U.S. Chamber of Commerce	U.S. Chamber of Commerce.
U.S. Climate Alliance	United States Climate Alliance.
U.S. Democratic Representatives	U.S. Representatives Paul D. Tonko and 112 additional U.S. Representatives.
U.S. DOE	United States Department of Energy.
U.S. DOJ and FTC	United States Department of Justice and the Federal Trade Commission.
U.S. House Republicans	U.S. Representatives Andrew R. Garbarino; Anthony D'Esposito; Nicholas A. Langworthy; and Brandon Williams.
U.S. Senator Barrasso	U.S. Senator John Barrasso.
U.S. Senator Heinrich	U.S. Senator Martin Heinrich.
U.S. Senators	U.S. Senators Martin Heinrich; Edward J. Markey; Peter Welch; John Hickenlooper; Angus S. King, Jr.; Ron Wyden; Robert P. Casey, Jr.; Sheldon Whitehouse; Tina Smith; Ben Ray Lujan; Chris Van Hollen; Mazie Hirono; Jeffrey A. Merkley; Brian Schatz; Thomas R. Carper; Bernard Sanders; Patty Murray; John Fetterman; Michael F. Bennet; Elizabeth Warren; and Alex Padilla.
U.S. Senators Heinrich and Lee	U.S. Senators Martin Heinrich and Mike Lee.
U.S. Senators Hickenlooper and King	U.S. Senators John Hickenlooper and Angus S. King, Jr.
U.S. Senator Schumer	U.S. Senator Charles E. Schumer.
U.S. Senator Whitehouse	U.S. Senator Sheldon Whitehouse.

ABBREVIATED NAMES OF COMMENTERS—Continued

Abbreviation	Commenter(s)
Utah Commission	The Utah Public Service Commission.
Utah Division of Public Utilities	Utah Department of Commerce, Division of Public Utilities.
VEIR	VEIR Inc.
Vermont Electric and Vermont Transco	Vermont Electric Power Company, Inc., and Vermont Transco LLC.
Vermont State Entities	The Vermont Public Utility Commission and the Vermont Department of Public Service.
Virginia Attorney General	Virginia Office of the Attorney General, Division of Consumer Counsel.
Virginia Commission Staff	The Staff of the Virginia State Corporation Commission.
Vistra	Vistra Corp.
WATT Coalition	The Working for Advanced Transmission Technologies (WATT) Coalition.
WE ACT	WE ACT for Environmental Justice.
West Virginia Commission	The Public Service Commission of West Virginia.
Western PIOs	Center for Energy Efficiency and Renewable Technologies; NW Energy Coalition; Western Resource Advocates; and Renewable Northwest; collectively, Western Public Interest Organizations.
Western State Representatives	Agency Representatives from the states of Arizona; California; Idaho; Montana; Nevada; Oregon; South Dakota; Utah; Washington; and Wyoming.
Western Way Colorado	Western Way Colorado.
Western Way Nevada	Western Way Nevada.
Western Way Utah	Western Way Utah.
Wildlife Federation Action Fund Supporters	8,610 Supporters of the National Wildlife Federation Action Fund.
WIRES	WIRES.
Wisconsin Conservative Energy Forum	Wisconsin Conservative Energy Forum.
Wisconsin Legislators	Wisconsin State Senator Julian Bradley and Wisconsin State Representative David Steffen.
Wisconsin Senator Cowles	Wisconsin State Senator Robert L. Cowles.
Xcel	Xcel Energy Services Inc.

Appendix B: Pro Forma Open Access Transmission Tariff Attachment K

Note: Proposed deletions are in brackets and proposed additions are in italics.

Attachment K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open, and transparent *local transmission* planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open, and transparent *local transmission* planning process shall be provided as an attachment to the Transmission Provider's Tariff. The Transmission Provider's *local transmission* planning process shall *provide stakeholders with meaningful opportunities to participate and provide feedback, and shall* satisfy the following nine principles, as defined in Order No. 890: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new *transmission* projects. The *local transmission* planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The *local transmission* planning process also shall provide a mechanism for the recovery and allocation of *transmission* planning costs consistent with Order No. 890. The

description of the Transmission Provider's *local transmission* planning process must include sufficient detail to enable Transmission Customers to understand:

- (i) The process for consulting with customers;
- (ii) The notice procedures and anticipated frequency of meetings;
- (iii) The methodology, criteria, and processes used to develop a transmission plan;
- (iv) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;
- (v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;
- (vi) The dispute resolution process;
- (vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;
- (viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; and
- (ix) The relevant cost allocation method or methods.

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms, and

conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order Nos. 1000 and 1920. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as [set out and explained]*established* in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The *description of the* regional transmission planning process *in the Tariff* also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of "*transmission* planning costs" consistent with Order Nos. 890 and 1000.

The regional transmission planning process shall include a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region. The regional transmission planning process shall be clear that enrollment will subject enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Each Transmission Provider shall maintain a list of enrolled entities in the Transmission Provider's Tariff.

The regional transmission planning process must include at least three stakeholder meetings concerning the local transmission planning process of each Transmission Provider that is a member of the transmission planning region. The three

meetings must occur before each Transmission Provider's local transmission planning information can be incorporated into the transmission planning region's transmission planning models. The three stakeholder meetings for local transmission planning information are the Assumptions Meeting, the Needs Meeting, and the Solutions Meeting, and the three stakeholder meetings must meet the requirements in Order No. 1920.

As part of the regional transmission planning process, the Transmission Providers in each transmission planning region shall conduct Long-Term Regional Transmission Planning, meaning regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs. As part of this Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region shall meet the requirements set forth in Order No. 1920, including: (1) identifying Long-Term Transmission Needs and Long-Term Regional Transmission Facilities to meet those needs through the development of Long-Term Scenarios that satisfy the requirements set forth in Order No. 1920; (2) measuring the required seven benefits consistent with the requirements set forth in Order No. 1920; (3) using the measured benefits to evaluate Long-Term Regional Transmission Facilities; and (4) using selection criteria consistent with the requirements set forth in Order No. 1920 that provide the opportunity for Transmission Providers to select Long-Term Regional Transmission Facilities in the regional transmission plan for purposes of cost allocation that more efficiently or cost-effectively address Long-Term Transmission Needs.

The process through which the Transmission Providers in each transmission planning region develop Long-Term Scenarios must comply with the following six transmission planning principles established in Order No. 890: coordination; openness; transparency; information exchange; comparability; and dispute resolution. The Transmission Providers in each transmission planning region shall outline in their Tariffs an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose potential factors and to provide input on how to account for specific factors in the development of Long-Term Scenarios. The Transmission Providers in each transmission planning region shall also outline in their Tariffs an open and transparent process that provides stakeholders, including states, with a meaningful opportunity to propose which future outcomes are probable and can be captured through assumptions made in the development of Long-Term Scenarios.

The Transmission Providers in each transmission planning region shall include in

their Tariffs a general description of how they will measure each of the seven required benefits used to evaluate Long-Term Regional Transmission Facilities. The Transmission Providers in each transmission planning region shall measure and use the seven benefits, as described in Order No. 1920, in Long-Term Regional Transmission Planning.

As part of Long-Term Regional Transmission Planning, the Transmission Providers in each transmission planning region shall include in their Tariffs an evaluation process, including selection criteria, that: (1) is transparent and not unduly discriminatory; (2) aims to ensure that more efficient or cost-effective transmission facilities are selected in the regional transmission plan for purposes of cost allocation; (3) seeks to maximize benefits accounting for costs over time without over-building transmission facilities; and (4) otherwise satisfies the requirements set forth in Order No. 1920.

The Transmission Providers in each transmission planning region shall include in their Tariffs one or more Long-Term Regional Transmission Cost Allocation Methods, which is an ex ante regional cost allocation method for one or more Long-Term Regional Transmission Facilities (or portfolio of such Facilities) that are selected in the regional transmission plan for purposes of cost allocation and that complies with the requirements set forth in Order No. 1920. The Transmission Providers in each transmission planning region may also, subject to (1) the agreement of Relevant State Entities and (2) Commission acceptance, include in their Tariffs a State Agreement Process. A State Agreement Process is a process by which one or more Relevant State Entities may voluntarily agree to a cost allocation method for Long-Term Regional Transmission Facilities (or a portfolio of such Facilities) either before or no later than six months after the facilities are selected in the regional transmission plan for purposes of cost allocation. The Tariff must describe how the State Agreement Process will result in a cost allocation being filed, including which entities can participate in the State Agreement Process; what constitutes an agreement on cost allocation in that process; how agreement is communicated to the transmission provider; and the circumstances under which, or the information necessary for, a transmission provider to file or to consider filing the agreed cost allocation.

As part of evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities, the Transmission Providers in each transmission planning region shall consider in all of their regional transmission planning and cost allocation processes whether selecting transmission facilities that incorporate the following technologies would be more efficient or cost-effective than selecting new regional transmission facilities or upgrades to existing transmission facilities that do not incorporate these technologies: dynamic line ratings, as defined in 18 CFR 35.28(b)(14), advanced power flow control devices, advanced conductors, and/or transmission switching. Specifically, such consideration must include both: (1) whether incorporating

dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching into existing transmission facilities could meet the same regional transmission need more efficiently or cost-effectively than other potential transmission facilities; and (2) when evaluating transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation, whether incorporating dynamic line ratings, advanced power flow control devices, advanced conductors, and/or transmission switching as part of any potential regional transmission facility would be more efficient or cost-effective.

Transmission providers must evaluate the benefits of incorporating the enumerated alternative transmission technologies into Long-Term Regional Transmission Facilities in a manner consistent with the requirements in the Evaluation of Benefits of Regional Transmission Facilities and Evaluation and Selection of Long-Term Regional Transmission Facilities sections of Order No. 1920.

The Transmission Providers in each transmission planning region shall evaluate for potential selection in the regional transmission plan for purposes of cost allocation regional transmission facilities that address interconnection-related transmission needs originally identified through the generator interconnection process. This requirement applies in the existing Order No. 1000 regional transmission planning processes. The Transmission Providers must modify their Tariffs to include these requirements. The interconnection-related transmission needs that Transmission Providers must evaluate in the existing Order No. 1000 regional transmission planning process are those for which:

(1) Transmission Providers in the transmission planning region have identified the relevant interconnection-related transmission need in interconnection studies in at least two interconnection queue cycles during the preceding five years (looking back from the effective date of the accepted tariff provisions proposed to comply with this reform in Order No. 1920, and the later-in-time withdrawn interconnection request occurring after the effective date of the accepted tariff provisions);

(2) the interconnection-related Network Upgrade identified through the generator interconnection process to meet the relevant interconnection-related transmission need has a voltage of at least 200 kV and an estimated cost of at least \$30 million;

(3) the interconnection-related Network Upgrade identified through the generator interconnection process to meet the relevant interconnection-related transmission need is not currently planned to be developed because the interconnection request(s) that led to the identification of the interconnection-related transmission need has been withdrawn; and

(4) the Transmission Providers have not identified a different interconnection-related Network Upgrade to meet the relevant interconnection-related transmission need in an executed Generator Interconnection

Agreement or in a Generator Interconnection Agreement that the interconnection customer requested that the Transmission Provider file unexecuted with the Commission.

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

- (i) The process for enrollment in the regional transmission planning process;
 - (ii) The process for consulting with customers;
 - (iii) The notice procedures and anticipated frequency of meetings;
 - (iv) The methodology, criteria, and processes used to develop a transmission plan;
 - (v) The method of disclosure of criteria, assumptions, and data underlying a transmission plan;
 - (vi) The obligations of and methods for transmission customers to submit data;
 - (vii) The process for submission of data by nonincumbent developers of transmission projects that wish to participate in the regional transmission planning process and seek regional cost allocation;
 - (viii) The process for submission of data by merchant transmission developers that wish to participate in the regional transmission planning process;
 - (ix) The dispute resolution process;
 - (x) The study procedures for economic upgrades to address congestion or the integration of new resources; and
- [The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order Nos. 1000; and]
- (xi) The relevant cost allocation method or methods.

The regional transmission planning process must include [a] cost allocation methods [or methods] that satisfy the [six regional cost allocation principles] requirements set forth in Order Nos. 1000 and 1920.

Identifying Potential Opportunities to Right-Size Replacement Transmission Facilities

As part of each Long-Term Regional Transmission Planning cycle, Transmission Providers in each transmission planning region shall evaluate whether transmission facilities operating at or above a voltage threshold not to exceed 200 kV that an individual Transmission Provider that owns the transmission facility anticipates replacing in-kind with a new transmission facility during the next 10 years can be "right-sized" to more efficiently or cost-effectively address Long-Term Transmission Needs, as discussed in Order No. 1920. The process to identify potential opportunities to right-size replacement transmission facilities must follow the process outlined in Order No. 1920. The Transmission Providers in each transmission planning region shall include in their Tariffs a cost allocation method for right-sized replacement transmission facilities that are selected in the regional transmission plan for purposes of cost allocation.

Interregional Transmission Coordination

The Transmission Provider, through its regional transmission planning process, must

coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

- (1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans (*including information regarding the Long-Term Transmission Needs and potential transmission facilities to meet those needs*) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities, as well as a procedure for doing so;
- (2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions, *including those that may be more efficient or cost-effective transmission solutions to Long-Term Transmission Needs*;
- (3) An agreement to exchange, at least annually, planning data and information; and
- (4) A commitment to maintain a website or email list for the communication of information related to the coordinated planning process, *including*:
 - (a) *the Long-Term Transmission Needs discussed in the interregional transmission coordination meetings*;
 - (b) *any interregional transmission facilities proposed or identified in response to the Long-Term Transmission Needs*;
 - (c) *the voltage level, estimated cost, and estimated in-service date of the interregional transmission facilities proposed or identified as part of Long-Term Regional Transmission Planning*;
 - (d) *the results of any cost-benefit evaluation of such interregional transmission facilities, with results including both any overall benefits identified, as well as any benefits particular to each transmission planning region*; and
 - (e) *the interregional transmission facilities, if any, selected in the regional transmission plan for purposes of cost allocation to meet Long-Term Transmission Needs.*

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or

methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000 and must be included in the Transmission Provider's Tariff.

United States of America—Federal Energy Regulatory Commission

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

Docket No. RM21–17–000

(Issued May 13, 2024)

PHILLIPS, Chairman, CLEMENTS, Commissioner, *concurring*:

1. The electric transmission grid is the backbone of the American economy and essential to the national security of our country. The mission of this agency is to ensure reliable, safe, secure, and economically efficient energy for consumers at a reasonable cost. Ensuring we have a robust, well-planned electric transmission grid is the single most important step that this Commission can take to fulfill that statutory mandate. It is a *reliability imperative*. The transmission grid ultimately allows consumers to have access to the electricity they need—when they need it—to power their homes and businesses. It is equally an *affordability imperative*. The transmission grid gives those same consumers access to diverse, low-cost sources of electricity that help ensure energy bills remain just and reasonable. All told, a strong electric transmission grid is the foundation for how this Commission meets its most important statutory responsibilities under the Federal Power Act (FPA).

2. That has never been more true than it is today. We are in the midst of a pivotal moment for the electricity system. As a nation, we are seeing unprecedented demands on the grid from extreme weather, increasing and rapidly changing patterns of electricity use, and fundamental shifts in the resource mix. And there is every reason to believe those trends will continue, and, indeed, accelerate, in the years ahead.

3. At the same time, our transmission grid is old. More than 70 percent of the grid was built over 25 years ago and much of it was put into service in the 1960s and 1970s, when this agency was still the Federal Power Commission. Our country cannot meet the challenges of today, let alone tomorrow, with yesterday's transmission system. And being unprepared to meet those increased demands jeopardizes the safety and security of our grid. Nevertheless, as a country, we have so far failed to make the investments in the types of transmission facilities needed to ensure continued reliability and affordability at anywhere near the scale or speed needed to meet this pivotal moment.

4. The cost of continued inaction is immeasurable. Failure to act now would hamper the reliability and resilience of our electric grid while leaving customers holding the bag for the inevitably more costly upgrades in the future. Indeed, under the

status quo, with its de facto emphasis on the piecemeal, just-in-time development of the grid to meet near-term reliability and economic needs, customers are being forced to fund investments that could have been more beneficial, less costly, or both had they been better planned from the start. That result undermines our economy and leaves customers less safe and secure, with enormous costs for both our grid and our country.

5. Avoiding those costs requires a forward-looking, comprehensive, and holistic transmission planning and cost allocation framework. That framework must consider the diverse challenges facing the transmission grid, identify the solutions that will address those challenges, and ensure only customers who benefit from those facilities pay their share of the cost, while ensuring that customers who do not benefit do not pay. Period.

6. We must conduct this planning and cost allocation on a regional basis and with an aperture consistent with the scope and scale of the challenges we face. That is, after all, why Congress enacted Title II of the FPA: To provide a coherent regional and national regulatory regime and avoid the harms and costs that come from a balkanized electricity system in which every state is its own regulatory island.¹

7. Today's final rule does just that. We are requiring transmission planners to plan Long-Term Regional Transmission Facilities using the factors we know drive the transmission needs of tomorrow and consider the reliability and affordability benefits those facilities will provide. At the same time, we are giving transmission planners discretion regarding whether and how to select which transmission facilities to build, recognizing no two regions of the country are alike and a one-size-fits-all solution simply will not produce the infrastructure we so badly need.

8. When it comes to the critical question of "who pays," we are providing transmission planners with the maximum flexibility we can legally allow in order to facilitate negotiated, regionally appropriate solutions. And, as part of a multi-pronged approach to protecting customers, we are requiring transmission planners to reevaluate any previously selected Long-Term Regional Transmission Facility when the actual or projected costs of that facility significantly exceed the cost estimates used during selection. Finally, we are also providing

states with unprecedented, expanded opportunities to work with transmission providers to shape the cost allocation approaches of their regions, while meeting the beneficiary pays requirement that is the foundation of cost causation under the FPA's just and reasonable standard.

I. The Dissent's Approach Would Not Result in the Energy Infrastructure Buildout We Need

9. Commissioner Christie provides a stark alternative vision in his dissent, one that would violate the cost causation principle and harm electric reliability. While we agree with his emphasis on the importance of cooperation with states—and have created unprecedented opportunities for such cooperation throughout this final rule—his radical new approach would permit a state to receive economic, resilience, and reliability benefits from new energy infrastructure, but not be charged a single cent unless they expressly agree to pay. That myopic view does not satisfy the requirements of the FPA and would not adequately facilitate the development of transmission we desperately need to ensure reliability and affordability. Contrary to the dissent's assertion that this final rule is the product of a political agenda, failing to act based on the dissent's flawed reading of the circumstances through the lens of politics would abdicate the Commission's duty.

10. The dissent's approach would necessarily require the Commission to ignore evidence about which consumers benefit from the increased reliability, resilience, and affordability due to grid expansion. Instead, backbone regional transmission could not be built unless every state unanimously opted into an agreed cost allocation. But for the same reason that passing around a hat is no way to fund the fire department, roads, or bridges, such an approach to building critical, public interest infrastructure that relies entirely on the voluntary contributions of individual states (or could even be defeated by the refusal to contribute by a single state) will not beget the transmission infrastructure needed to maintain reliability and affordability.

11. Put another way, there is little reason to believe that we, as a country, would build the infrastructure needed to power the world's largest economy if individual states that benefit from that infrastructure could simply decline to pay. Instead, Commissioner Christie's approach would be far more likely to result in a failure to make needed investments entirely, or else to down-size those investments in a way that results in exactly the type of piecemeal transmission development that led us to conclude existing transmission planning practices are rendering transmission rates unjust and unreasonable. That result would leave America far worse off. Just as the Articles of Confederation were not a sufficient platform to develop and sustain a national economy, so too would a wholly voluntary approach to paying for the needed infrastructure be inadequate to develop a transmission grid capable of powering the world's largest economy. That alone is a reason to reject Commissioner Christie's dissenting views.

12. In addition, the dissent's approach would result in subpar transmission planning. Our nation needs transmission planning that looks ahead on the decades-long timeframe that is relevant to building backbone transmission facilities that will likely last a half-century or more. And transmission needs can best be predicted by considering many factors to discern their aggregate effect. Those include economics and technology fundamentals, changing demand patterns across customers of all types (including corporations), the full panoply of federal, Tribal, state, and local policy contributions, and even the changing weather patterns, which pose increasing challenges to maintaining a reliable and resilient electric grid. Rather than reflect that integrated reality, Commissioner Christie's approach asks planners to isolate select state public policies and focus on how each individually shapes the grid. That too is a recipe for down-sizing needed infrastructure in a way that will result in less efficient or cost-effective investments that fail to meet this critical moment.

II. The Dissent Misrepresents the Final Rule

13. Commissioner Christie's dissent responds to a strawman of his own making, not the final rule. And, even so, the dissent's critique of the final rule ultimately boils down to one principal issue: the failure of the rule (in his view) to give every state an absolute right to veto the costs of a transmission facility, even one from which the state's consumers would derive economic and reliability benefits. Although we respect his perspective, we disagree that the changes he seeks are legal—much less legally required—or that a final rule premised on his vision would beget the energy infrastructure needed to maintain reliability and affordability. In any case, his statement mischaracterizes critical aspects of the final rule, the most fundamental of which we address below.

14. First and foremost, Commissioner Christie asserts that Long-Term Regional Transmission Facilities are public policy projects whose purpose is to facilitate state efforts to shape the resource mix. He is wrong. This final rule requires transmission providers to comprehensively consider the factors that will shape the transmission needs of tomorrow. Although state efforts to shape the resource mix are one of many factors transmission planners are required to consider under this final rule, Commissioner Christie's narrow focus on them misses the forest for a couple trees. The requirement to consider state public policies is part of the much broader requirement to comprehensively consider *all* significant factors shaping future transmission needs, where other factors, including the fundamental economic and reliability drivers, play a much bigger role. That Commissioner Christie is focused overwhelmingly on the state public policies with which he disagrees does not mean that the same is true of Long-Term Regional Transmission Facilities.

15. In any case, Commissioner Christie's proposal is arbitrary and capricious in its lack of any limiting principle. Transmission

¹ *New York v. FERC*, 535 U.S. 1, 6 (2002) ("When it enacted the FPA in 1935, Congress authorized federal regulation of electricity in areas beyond the reach of state power," tasking the Commission's predecessor with "effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce." (quoting *Gulf States Utils. Co. v. F.P.C.*, 411 U.S. 747, 758 (1973))); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 265–66 (2016) (*EPSA*) (same); cf. *First Iowa Hydro-Elec. Co-op v. F.P.C.*, 328 U.S. 152, 180 (1946) (The Federal Water Power Act of 1920 was "a complete scheme of national regulation which would promote the comprehensive development of the water resources of the Nation, in so far as it was within the reach of the federal power to do so, instead of the piecemeal, restrictive, negative approach of the River and Harbor Acts and other federal laws previously enacted.").

needs of all sorts—economic or reliability, near-term or long-term—are shaped by all manner of state public policy choices. Fundamental state decisions, such as tax rates, zoning and land use laws, and almost every use of the police power more generally, inevitably shape the supply and demand of electricity. No transmission need is unaffected by those basic exercises of state power, which means that no transmission need can be fairly or accurately described as entirely divorced from the effects or consequences of state policy decisions.

16. While taking issue with some state policy choices, Commissioner Christie's vision contains no method for determining which state policies must be considered and which might escape scrutiny even though they too contribute to underlying transmission needs. Similarly, it contains no rubric for determining how to evaluate the cumulative effects of state public policies—such as taxation and land use laws—that are, in many cases, far in excess of those derived from the public policies on which he chooses to focus. Nor does it contain any explanation for subjecting Long-Term Regional Transmission Facilities to this suite of planning and cost allocation requirements, but not economic and reliability projects—which are, for the reasons noted above, inevitably at least in part the product of public policies. That sort of unexplained, arbitrary line drawing is exactly what the APA prohibits.²

17. Let us be clear: These are reliability and affordability projects. As the final rule explains, the minimum standards we establish provide that Long-Term Regional Transmission Facilities are to be identified and evaluated based on their reliability and economic benefits. To call them anything else—no matter how many times—is a misnomer, plain and simple.

18. Similarly, Commissioner Christie's claim that states will be forced to subsidize other states' public policy choices could not be further from the truth. A bedrock requirement of this final rule is that customers will only be required to pay for a share of a Long-Term Regional Transmission Facility to the extent they benefit from that facility. That is cost causation 101. While we provide transmission planners, in cooperation with their state regulators, ample flexibility to determine how to satisfy that bedrock requirement, any cost allocation methodology that causes customers to pay for projects from which they do not benefit—or to pay a cost share out of proportion to the benefits they draw from the project—would

be patently unjust and unreasonable. That is black letter law under the FPA,³ which we have expressly incorporated into the requirements of this final rule.⁴

19. The dissent is equally wrong to suggest that anything less than a unilateral right to veto cost responsibility for a regional transmission project is unfair to states. To the contrary, both courts and the Commission have long recognized that the just and reasonable standard of the FPA requires that customers pay for infrastructure they use and benefit from.⁵ The dissent's approach, by contrast, would permit free ridership, allowing states to avoid paying by withholding their approval, while still receiving the substantial benefits of a more integrated, robust transmission system. Here too, both the Commission and the courts have expressly rejected that approach as inconsistent with cost causation.⁶ Rather

³ See *City of Lincoln v. FERC*, 89 F.4th 926, 930 (D.C. Cir. 2024) (“The FPA’s just and reasonable standard incorporates a cost-causation principle.”); *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018) (“Under the [FPA], electric utilities must charge just and reasonable rates. For decades, the Commission and the courts have understood this requirement to incorporate a cost-causation principle—the rates charged for electricity should reflect the costs of providing it.” (citations omitted)); see also *BNP Paribas Energy Trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014) (“[T]he cost causation principle itself manifests a kind of equity. This is most obvious when we frame the principle (as we and the Commission often do) as a matter of making sure that burden is matched with benefit.”).

⁴ *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, Order No. 1920, 187 FERC ¶ 61,068, at P 1305 & n.2786 (2024).

⁵ Beneficiary pays is founded on a recognition, grounded in the unbreakable laws of physics, that “the nature of power flows over an interconnected transmission system does not permit a public utility transmission provider to withhold service from those who benefit from those services but have not agreed to pay for them.” Order No. 1000, 136 FERC ¶ 61,051 at P 534; see also *id* P 535 (“the cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them”); *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476–77 (7th Cir. 2009) (*ICC v. FERC I*) (“All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. . . . To the extent that a utility benefits from the costs of new facilities, it may be said to have caused a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.” (internal citations omitted)); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (“FERC and the courts have added flesh to these bare statutory bones, establishing what has become known in Commission parlance as the ‘cost-causation’ principle. Simply put, it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.”); see, e.g., *Sw. Power Pool*, 182 FERC ¶ 61,141, at PP 12, 99–103 (2023).

⁶ Order No. 890, 118 FERC ¶ 61,119 at P 561 (“there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefits from it”); Order No. 1000, 136 FERC ¶ 61,051 at P 535 (“[if] the Commission could not address free rider problems associated with new transmission

than ensure fairness, the dissent's approach would create perverse incentives, rewarding states that decline to pay for infrastructure development that demonstrably provides reliability and economic benefits to those states, while penalizing those who roll up their sleeves to get those projects built. That is a recipe for inaction, not for building the energy infrastructure we so badly need to maintain reliability and affordability.

20. We agree with Commissioner Christie that transmission development works best when states are key partners in the process. That is why we take the unprecedented steps described in the final rule to give them a central role. But partnership and collaboration are not the same thing as giving every state the right to veto cost responsibility for transmission projects thus allowing their residents to reap a windfall by benefitting from transmission facilities for which they did not pay their legally required share.

21. Commissioner Christie also asserts that the final rule deprives states of their longstanding authority. That is categorically false. Let us again be clear: States retain all the same authorities over retail rates and transmission siting they held prior to the final rule. Rather than deprive states of authority, the final rule *empowers* them with unprecedented opportunities to engage with transmission providers in developing a cost allocation framework.

22. Commissioner Christie's objection is to the structure of the FPA, and long-established, court-upheld Commission regulation of regional transmission planning under Order No. 1000, not the final rule. He objects to the transmission provider's role in deciding, without state approval, whether to invest in a transmission project and determine, subject to Commission oversight, which consumers must pay for it. But that basic structure is not new to the final rule—it is how transmission planning occurs today, consistent with the FPA and Commission precedent, including Order No. 1000. At Congress's direction, public utilities, not states, have the right to propose to the Commission rates and practices affecting those rates and we cannot deprive them of those rights.⁷ Neither states' siting authority nor their exclusive jurisdiction over retail rates give them the unilateral right to dictate matters subject to the Commission's exclusive jurisdiction, such as the transmission rates and practices affecting those rates that are the subject of this final rule.⁸ For example, a state could reject siting

investment, [] it could not ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory”); *El Paso Elec. Co. v. FERC*, 76 F.4th 352, 363 (5th Cir. 2023) (“No amount of emphasizing other competing interests permits FERC to sacrifice the foundational principle of cost-causation by refusing to allocate costs to those who cause the costs to be incurred and who reap the resulting benefits.” (citations omitted)).

⁷ 16 U.S.C. 824d; *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) (“Section 205 of the Federal Power Act gives a utility the right to file rates and terms for services rendered with its assets.”).

⁸ See Order No. 1920, 187 FERC ¶ 61,068 at PP 253–83 (affirming Commission's legal authority to

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² See, e.g., *Prometheus Radio Project v. F.C.C.*, 373 F.3d 372, 390 (3rd Cir. 2004) (explaining that when an agency has engaged in line-drawing, “its decisions may not be ‘patently unreasonable’ or run counter to the evidence before the agency” (citations omitted)); *Sinclair Broadcast Grp., Inc. v. F.C.C.*, 284 F.3d 148, 162 (D.C. Cir. 2002) (explaining that lines drawn cannot be “patently unreasonable, having no relationship to the underlying regulatory problem” (citing *Cassell v. F.C.C.*, 154 F.3d 478, 485 (D.C. Cir. 1998)); *Am. Trucking Assocs., Inc. v. I.C.C.*, 697 F.2d 1146, 1151 (D.C. Cir. 1983) (“The arbitrariness which the [Administrative Procedure Act] proscribes is the failure to draw reasoned distinctions where reasoned distinctions are required.”).

or other approvals for the portion of a regional transmission project located within its jurisdiction, provided that its determination was consistent with relevant state and federal law. But states cannot stymie needed regional transmission projects by simply declining to pay for them. Nor is that concept new to this final rule. Under established economic and reliability planning, state policies are contributing factors to needed transmission, and states have never held a veto authority over costs for such facilities under Order No. 1000.⁹ Nothing in this final rule changes those basic facts.

23. What has changed is that states now, *as a result of this final rule*, have an unprecedented opportunity to shape transmission planning and cost allocation, elevating our system of cooperative federalism with the states to a degree not previously seen in the history of this Commission. Most significantly, we are requiring transmission providers to host a dedicated forum for meaningful state participation in proposing cost allocation methods and processes. And the rule also permits a State Agreement Process for allocating the costs of all, or a subset of, Long-Term Transmission Facilities. Beyond cost allocation, states will have an opportunity to provide input on how to account for specific factors in Long-Term Scenarios, and states can provide information on how their own policies and planning affect Long-Term Transmission Needs. The rule also requires transmission providers to consult with and seek the support of states regarding how Long-Term Regional Transmission Facilities are evaluated and selected. We expect that where states come together to articulate workable, legal frameworks for planning and paying for needed infrastructure, their transmission providers will listen.

24. Indeed, under the State Agreement Process provided in the final rule, states very well could agree to, and transmission planners could adopt, a version of Commissioner Christie's preferred cost allocation approach.¹⁰ So long as those

require participation in Long-Term Regional Transmission Planning).

⁹ Indeed, Commissioner Christie recently approved, over the objection of other states, PJM's plan to regionally allocate the costs of transmission to address reliability concerns driven, at least in part, by Virginia's policy to incent siting of data centers in that state. *See PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,012 (2024).

¹⁰ We find Commissioner Christie's contention that the final rule would end PJM's use of its existing State Agreement Approach, and MISO and SPP's respective regional state committees, puzzling. Order No. 1920, 187 FERC ¶ 61,068 (2024) (Christie, Comm'r, dissenting, at P 11). The final rule enhances states' role and relaxes certain Order No. 1000 requirements for state-approved cost allocations. It is inexplicable that these additional flexibilities would result in transmission providers rolling back opportunities for state engagement in existing Order No. 1000 processes, where that is the opposite of the thrust of the final rule. Moreover, PJM's State Agreement Approach was approved outside of compliance with Order No. 1000 and has never served as PJM's exclusive *ex ante* cost allocation method, as Commissioner Christie suggests.

expected to use the Long-Term Regional Transmission Facilities pay a share of the cost that is roughly commensurate with the benefits they will receive, nothing in this final rule prohibits states in a transmission planning region from adopting Commissioner Christie's preferred approach for funding the transmission facilities they need to ensure reliability and affordability.

25. Commissioner Christie also asserts that this final rule breaks with Order No. 1000 by mandating outcomes rather than regulating transmission planning processes. Here, too, he is wrong. The rule is clear that no transmission provider is required to select any particular project.¹¹ Instead, just as in Order No. 1000, the obligation on the transmission provider is to plan for the world as we expect it to be and then make its own business decisions after having conducted that planning process. The final rule's minimum planning standards do not un-do that core discretion. Requiring planning to be based upon documented drivers of transmission needs and to incorporate objective measures of how potential investments pay off improves the planning process, it does not mandate any particular outcome.¹² In short, in recasting the rule to fit his narrative, Commissioner Christie conveniently ignores one of its core elements: that it imposes no obligation to develop any regional transmission project.

26. Finally, Commissioner Christie is also incorrect in arguing that this final rule violates the Major Questions Doctrine. He asserts two bases for that argument, neither of which hold water.

27. First, he contends that our *intention* in issuing this final rule is to elicit trillions in spending on transmission. As an initial matter, the goal of this final rule is to facilitate the development of transmission infrastructure needed to maintain reliability and affordability. That is the case no matter how many times or in how many ways Commissioner Christie purports to ascribe our 'true' intentions. In any case, his trillion-dollar estimates are nothing more than a sleight of hand that is unsupported by the record before us. To support his claim that this final rule will cause "literally trillions" in transmission investment, he cites to one academic study and one news article stating that in order to achieve a "net-zero" emissions level by 2050, trillions will need to be spent on transmission.¹³ Putting aside whether that figure is accurate and whether "net zero" is an appropriate policy goal for the country—a question which we agree is not for this Commission to resolve—it is an astounding logical leap to say that because

certain individuals believe a certain amount of investment is necessary to achieve a certain policy goal, that this rule will necessary cause customers to spend that amount of money. In any case, as the dissent points out, significant investments in transmission are already being made by public utilities around the country regardless of anything we do—or do not do—here today. This final rule regulates the process by which those investments are identified, evaluated and, where appropriate, selected in order to help ensure that they reflect the most efficient and cost-effective options available. That is what the Commission has been doing for decades; the fact that transmission has become a more politically salient topic does not transform our longstanding practice into a major question.

28. Second, he contends that our statement that the Commission has exclusive jurisdiction over the transmission planning practices that directly affect wholesale rates means that this Commission has crossed the major questions Rubicon. But it was the courts, not this Commission, that took that step. As he observes in his dissent, *South Carolina* concluded that the transmission planning practices regulated by Order No. 1000—which are the same practices addressed by this final rule—were practices that directly affected wholesale rates and thus fall squarely within the Commission's jurisdiction.¹⁴ And as the courts have explained, where a practice meets that directly affecting standard, it falls within the Commission's exclusive jurisdiction.¹⁵ This long-settled law in no way alters or dilutes the significant and critical role for states to play under their jurisdiction and, as noted above, we have significantly expanded that role in this final rule. Rather it means that the specific practices in the tariffs on file with this Commission, as required by this final rule, are within the Commission's exclusive jurisdiction, not that of the states. The final rule's recitation of black letter law hardly runs afoul of the major questions doctrine.

III. We Encourage Transmission Providers To Facilitate Joint Ownership Structures

29. Finally, we would be remiss not to mention one policy priority that is not finalized in this rule: The creation of a federal right of first refusal for certain transmission facilities developed through a joint ownership structure. As the final rule explains, we find that proposal is better considered as part of our generic proceeding on Transmission Planning and Cost Management, where it can be evaluated

¹⁴ In *South Carolina*, it was undisputed that transmission planning generally was a practice that directly affected wholesale rates, but the court further held that the absence of regional transmission planning was itself such a practice. *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 56–59 (D.C. Cir. 2014).

¹⁵ See, e.g., *Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 964 F.3d 1177, 1181 (D.C. Cir. 2020) ("Congress [gave] the Federal Energy Regulatory Commission . . . exclusive authority over the regulation of the sale of electric energy at wholesale in interstate commerce, including both wholesale electricity rates and any rule or practice affecting such rates." (cleaned up)).

¹¹ Order No. 1920, 187 FERC ¶ 61,068 at P 1026 ("The Commission did not propose in the NOPR, and we will not require in this final rule, that transmission providers select any particular Long-Term Regional Transmission Facility—even where a particular transmission facility meets the transmission providers' selection criteria in their OATTs.").

¹² *Id.* ("In other words, as in Order No. 1000, our focus is on ensuring that regional transmission planning processes result in just and reasonable rates, and not on requiring that these processes achieve any particular substantive outcome.").

¹³ *Id.* (Christie, Comm'r, dissenting at P 3 & n.7.

alongside other proposals for ensuring that transmission facilities are developed as efficiently and cost-effectively as possible.¹⁶

30. Nevertheless, we underscore that our decision today should not be construed as a lack of support for the concept of joint ownership or the potential for a federal ROFR to effectively encourage its use. Indeed, joint ownership structures that partner transmission owners with other load-serving entities in their footprint, such as public power or non-profit cooperatives, can provide many benefits and should be encouraged.

31. In these arrangements, the load-serving entity partner's participation can reduce costs for customers in the footprint. Such joint ownership structures bring together diverse parties, allowing the participating entities to better allocate risks and responsibilities, capture efficiencies, and promote innovation, all to customers' ultimate benefit.¹⁷ Moreover, by bringing a wider range of entities into the transmission development fold, joint ownership can leverage additional sources of capital, including those that do not typically invest in transmission facilities, which can itself have significant benefits for customers.¹⁸

32. For example, TAPS highlights specific instances of joint ownership arrangements with tax-exempt public power entities providing significant savings to customers.¹⁹ TAPS and APPA estimate these kinds of joint ownership arrangements can typically yield a "more than a 5% annual cost reduction in

ratepayer-funded return and associated tax costs," which could produce billions of dollars in savings when applied to reasonable transmission investment forecasts.²⁰ Relatedly, NRECA highlights examples of joint ownership arrangements with electric cooperatives yielding reliability and efficiency benefits, including, among others, leveraging electric cooperative's ability to provide increased operations and maintenance support and access to lower cost financing through the Rural Utilities Service.²¹

33. In light of those substantial benefits, we clarify that nothing in this final rule should be interpreted to prohibit or impair joint ownership arrangements. To the contrary, we encourage transmission providers, in compliance with this rule and elsewhere, to find ways to encourage these arrangements. For example, in compliance with this rule, transmission planners could use joint ownership as a factor to be considered in evaluating and selecting the more efficient or cost-effective solution to meet a long-term transmission need. Similarly, we note that the developers of a jointly owned transmission facility can consider seeking transmission incentives under section 205 of the FPA that reflect the risks and challenges associated with developing such facilities.²² In addition, the Commission will continue to evaluate other potential actions to incentivize joint ownership, including considering in the Commission's cost management proceeding whether to provide a right of first refusal or other mechanisms to encourage its use.

* * * * *

34. Our electric transmission grid is at a crossroads. Our nation is facing down an extended period of unprecedented change in demand, supply, and the myriad other factors that fundamentally shape our energy needs. And we do so with a network of transmission infrastructure that was overwhelmingly built in the last century and in the face of a very different reality.

35. We have a choice: We can take consequential action to build the infrastructure needed to ensure reliability and affordability. Or we can pursue half-measures, which may help on the margins, but will ultimately leave us lacking the

infrastructure we need to keep the lights on at a price that customers can afford. With this final rule, we emphatically choose the former path.

36. But we are not going down this road alone. As discussed above, we have opened the door for our state partners to play a leading role in shaping the next generation of energy infrastructure. We urge them to walk through it and deploy their unique perspectives as regulators and siting authorities of electric infrastructure to develop regionally tailored solutions. Together, we can forge a process that will serve customers for generations to come. This is the moment to step up, to develop both processes and physical infrastructure to withstand the changes and challenges ahead. This is the moment to build an electric transmission grid for the 21st century.

For these reasons, we respectfully concur.

Willie L. Phillips
Chairman

Allison Clements
Commissioner

United States of America—Federal Energy Regulatory Commission

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation

Docket No. RM21–17–000

(Issued May 13, 2024)

CHRISTIE, Commissioner, *dissenting*:

I. The Final Rule Is a Pretext for Enacting a Sweeping Policy Agenda Never Passed by Congress, Denies the States the Authority Promised by the NOPR, and Fails the Commission's Consumer Protection Duty Under the Federal Power Act

1. The Federal Power Act (FPA) is, at its core, a consumer protection statute.¹ In FPA section 206, which today's final rule purports to be based on, Congress explicitly directed this Commission to protect consumers from public utility "rates" that are "unjust, unreasonable, unduly discriminatory or preferential."² This final rule, however, fails

¹ E.g., *Towns of Alexandria, Minn. v. FPC*, 555 F.2d 1020, 1028 (D.C. Cir. 1977) (explaining that the FPA's "'primary aim is the protection of consumers from excessive rates and charges'" (quoting *Mun. Light Bds. v. FPC*, 450 F.2d 1341, 1348 (D.C. Cir. 1971)); see also *Elec. Dist. No. 1 v. FERC*, 774 F.2d 490, 492 (D.C. Cir. 1985) (recognizing that the benefits of rate predictability, which are the "whole purpose" of the filed rate doctrine, ought to be considered in light of the FPA's "primary purpose of protecting the utility's customers").

² 16 U.S.C. 824e. Under the FPA, the Commission is a regulator of wholesale public utility rates, not a national integrated resource planner (known in the lingo as an "IRP") of generation and/or transmission. See, e.g., *Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d 393, 417 (2d Cir. 2013) (quoting *S. Cal. Edison Co. San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269, at 62,080 (1995) ("[S]tates have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction. States may, for example, order utilities to build renewable generators themselves, or . . . order utilities to purchase renewable

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¹⁶ Order No. 1920, 187 FERC ¶ 61,068 at PP 1563–64 & n.3346.

¹⁷ See, e.g., TAPS Initial Comments at 33–34 ("As explained in the TAPS 2021 White Paper, inclusive joint transmission ownership arrangements—whether structured as an inclusive transco, a shared system, or joint ownership of new transmission facilities—result in collaborative and inclusive planning, development, and siting of transmission, and have proven highly effective in getting transmission built to meet the needs of all LSEs." (citing TAPS, *Inclusive Joint Transmission Ownership Arrangements: An Effective Means to Site and Build Transmission Need to Support Our Changing Resource Mix* (June 2021), <https://www.tapsgroup.org/wp-content/uploads/2021/09/TAPS-Inclusive-Joint-Ownership-White-Paper.pdf>)); see also Rob Gramlich et al., *Grid Strategies, Fostering Collaboration Would Help Build Needed Transmission*, at 11–30 (Feb. 2024) (attached to WIRES Supplemental Comments) (highlighting specific examples of large regional transmission projects that resulted from diverse partnerships, including with public power entities and cooperatives, and which met many transmission needs and produced a wide range of benefits).

¹⁸ See, e.g., APPA Initial Comments, attach. at 4–10 (Declaration of James Pardikes) (listing advantages in equity ratio, debt cost, and income tax expense, and opportunities for risk diversification as potential benefits of joint ownership arrangements with public power utilities); NRECA Reply Comments at 15–16; Citizens Energy Reply Comments at 2–4 (describing how its unique joint ownership business model enables Citizens to provide direct support to low-income ratepayers and disadvantaged communities, addresses multiple concerns that arise in transmission development, and advances multiple Commission policy goals).

¹⁹ TAPS Initial Comments at 45 (examining savings across Vermont Transco, ATCLLC, Fargo Project, and SE Missouri Project).

²⁰ TAPS Initial Comments at 45–46 & nn.133–135; APPA Reply Comments at 4.

²¹ GDS Assocs., *National Rural Electric Cooperative Association*, at 25–27 (Aug. 17, 2021) (attached to NRECA Initial Comments).

²² See *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129, at P 24 (2012) ("The Commission encourages incentives applicants to participate in joint ownership arrangements and agrees with commenters to the NOI that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks."); *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 116 FERC 61,057, at P 354 (2006) ("[T]o the extent our jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project. Encouraging public power participation in such projects is consistent with the goals of section 219 by encouraging a deep pool of participants.").

to fulfill the Commission's consumer protection duty required by the statute. The final rule should be seen for what it is: a pretext to enact, through administrative action, a sweeping legislative and policy agenda that Congress never passed.³ The final rule claims statutory authority the Commission does not have to issue an absurdly complex bureaucratic blizzard of mandates and micromanagement⁴ to be imposed on every transmission provider in the United States for the transparent goal of spending trillions of consumers' dollars on transmission *not* to serve consumers in accordance with the FPA, but instead to serve political, corporate, and other special-interest agendas that were never enacted into law.⁵ The rates for transmission that will

generation."'). Further, FPA section 215, pertaining to electric reliability, explicitly leaves the construction of generation and transmission assets to state regulatory authority. 16 U.S.C. 824o(i)(2). Section 215 makes clear congressional intent to leave integrated resource planning to the states. Indeed, the overall statutory framework of the FPA—consistent with America's federal constitutional structure—makes it clear that *states* are the primary regulators of which utility assets get planned and built, both generation and transmission, not FERC.

³ See, e.g., *W. Va. v. EPA*, 597 U.S. 697 (2022) (*West Virginia v. EPA*); *Dept. of Commerce v. N.Y.*, 139 S. Ct. 2551 (2019).

⁴ In truly Kafkaesque fashion, the final rule is a doorstopper weighing in at just below 1300 pages, likely one of the longest, most complicated, and confusing orders the Commission has ever issued. Regulated entities—it applies to *all* public utility transmission providers in the United States, RTO and non-RTO—will need weeks just to read through it, much less decipher it, and then months of figuring out how to comply. Its very complexity raises the prospect of multiple rounds of compliance filings, no doubt punctuated by multiple deficiency letters, in order to push the transmission provider towards the outcomes the Commission wants to achieve. The final rule's very complexity renders it, if not arbitrary and capricious in its face, likely to be arbitrary and capricious in its enforcement.

⁵ See, e.g., Heather Richards, Zach Bright, Christian Robles, *3 energy issues to watch this spring at DOE, Interior and FERC*, Energywire, Mar. 18, 2024 ("FERC has promised a closely watched rule this spring on transmission that could be key to President Joe Biden's ambitious aim to decarbonize the electricity grid by 2035 . . . 'The sooner we get a final rule, the better. . .,' said Caitlin Marquis [of] Advanced Energy United, a pro-clean-energy group . . . [T]he Biden administration is in a race . . . until roughly midyear to finalize rules before they are subject to the Congressional Review Act (CRA). . . . The Biden administration has said [today's final rule] will facilitate a build-out of interregional lines and grid interconnections needed to . . . allow more wind and solar power to come online . . .") (emphases added) <https://www.eenews.net/articles/3-energy-issues-to-watch-this-spring-at-doe-interior-and-ferc/>; see also Peter Behr, *EPA power plant rule targets coal. Does that spell trouble for the grid?* Climatewire, May 3, 2024 ("But climate activists will not give up the 'zero by 2035' goal without a fight. President Biden made that steep commitment at a critical point in his 2020 candidacy to win the support of primary rival Sen. Bernie Sanders (I-Vt.) and his climate action activists . . . [T]he hard road to a zero-carbon grid in 2035 is real precisely because the Biden administration has pursued it . . . [Study authors] highlighted estimates that the rate of high-voltage transmission line construction must double to deliver the necessary

result from the final rule will not only be unjust, unreasonable, unduly discriminatory and preferential, but grossly unfair to tens of millions of American consumers already burdened with rapidly growing monthly power bills.

2. The fundamental principle historically embedded in utility regulation in the United States is to provide consumers with *reliable* power at the *least* cost under applicable law. This principle is fair and compelling because the vast majority of American utility consumers are captive customers who pay a monopoly utility for a vital public service—electrical power—which no one can live without in modern society. Transmission is an essential component of this vital public service,⁶ so necessary transmission must be built.

new wind and solar energy . . . The [Biden] administration . . . is putting a strategy for big new lines in place. *FERC, with the support of Biden appointees, is preparing new policy to support big wires projects . . .* 'You can't get around the fact that you're going to need tens of thousands of miles of new transmission lines if you want to build the hundreds of gigawatts of wind and solar and batteries that many of us predict are needed to achieve decarbonization goals,' said [former Obama energy secretary Ernest] Moniz." (emphases added), <https://www.eenews.net/articles/epa-power-plant-rule-targets-coal-does-that-spell-trouble-for-the-grid-2/>; see also Zach Bright, *FERC sets date for landmark transmission rule*, Energywire, Apr. 19, 2024 ("FERC said it plans to hold a special May 13 meeting to consider its . . . transmission planning and cost-allocation proposal that's been a focus of [lobbying] for expanding the grid to . . . move more renewable energy . . . The Biden administration's goal of [net zero] by 2035 hinges on expanding the transmission system by two-thirds, the Energy Department said last year.") (emphases added), <https://www.eenews.net/articles/ferc-sets-date-for-landmark-transmission-rule/>; *It's raining rules: Why the Biden administration is rushing to produce regulations*, The Economist, May 4, 2024, at 19 ("More regulations, big and small, are expected soon. The Federal Energy Regulatory Commission is planning to rewrite the rules governing interstate electricity transmission, which is critical to President Joe Biden's decarbonisation plans . . . Why the sudden spate? A previously obscure law, the [CRA], helps explain the rush. It allows Congress, for a limited period, to pass resolutions of disapproval against finalised administrative regulations with which it disagrees. If both chambers of Congress pass such a resolution, and the president signs it, the rule is cancelled, short-circuiting the usual drawn-out process of litigation or a subsequent administration beginning a whole new rule-making effort. So once a regulation is properly created the clock starts ticking: the cancellation procedure is allowed for up to 60 days that the Senate is in session—including the last 60 days of an administration that loses a presidential election.") (emphasis added), <https://www.economist.com/united-states/2024/05/02/why-the-biden-administration-is-rushing-to-produce-regulations>; see *infra* nn.8, 10, 13, 15, 16, 67.

⁶ The transmission component of utility service has typically been provided by the incumbent monopoly utility at the load-serving local level, and local transmission planning and/or construction is generally subject to state-regulated IRP or permitting processes, especially in non-RTO regions. The final rule imposes numerous additional requirements for local transmission planning, including even micromanaging how local "stakeholder" meetings are supposed to be conducted, which may conflict with state IRP proceedings and represent yet another FERC

3. Today's final rule, however, is not about providing reliable power to consumers at least cost through just and reasonable rates as required by the FPA, despite the final rule's claim. And it is certainly not about being fair. On the contrary, the final rule inflicts staggering costs on consumers by promoting the construction of trillions of dollars of transmission projects,⁷ not to serve consumers in accordance with the FPA, but to serve a major policy agenda never passed by Congress, to serve the profit-making interests of developers of politically preferred generation, primarily wind and solar, and to serve corporate "green energy" preferential purchasing policies.⁸ As such, the final rule

encroachment into areas of traditional state authority. See *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, Order No. 1920, 187 FERC ¶ 61,068, at Section IX.B.3.a (2024) (Final Rule). It is highly doubtful that the micromanagement of stakeholder meetings in local planning would pass judicial review under *CAISO v. FERC*, in which FERC's attempted micromanagement of an ISO's governing board appointments was rejected as not sufficiently grounded in FERC's rate-setting authority under the FPA. See *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 400 (D.C. Cir 2004) (*CAISO v. FERC*).

⁷ The Princeton Net Zero study is often cited, but it is only one of many estimates of the trillions of dollars in additional costs to be imposed on consumers. Using the Princeton study, the cost estimates of the transmission buildout necessary to achieve "net zero" range across different scenarios, with one scenario calling for transmission capacity to quintuple (5x) between 2020 and 2050, which is predicted to cost \$3.56 trillion. See Princeton University Net Zero America Final Report Summary, Slide 29, [https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20\(29Oct2021\).pdf](https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf). I would emphasize that the sticker price of a utility asset is only a fraction of the ultimate cost to consumers, because the "going in" price will increase by a multiple of many times the original cost over the life of the asset, because the cost of capital, both a profit to the utility (known as Return on Equity, or ROE) and the cost of debt, will be paid by consumers. So, if Princeton gives an estimate of \$3.56 trillion for new utility assets needed to reach the "net zero" goal, the *actual* cost to consumers over the life of the assets will be many times more than that estimate. See also Diana DiGangi, *U.S. won't reach net zero emissions without transmission buildout*, DNV, Utility Dive, Sept. 25, 2023 (" '\$12 trillion will be spent on clean energy in North America by 2050 . . . to meet . . . net zero emissions targets . . . Some of the biggest barriers to net zero in the U.S. include the lack of transmission buildout . . .') (emphases added), <https://www.utilitydive.com/news/net-zero-transition-clean-energy-north-america-transmission-buildout/694621/>.

⁸ See, e.g., Peter Behr, *DOE unveils critical grid corridors for Biden climate goals*, Energywire, May 8, 2024 (" 'To meet our climate goals we have to more than double our transmission capacity,' said top White House clean energy adviser John Podesta, who has led a Cabinet-level push to get long-delayed transmission projects under construction.") (emphasis added), <https://www.eenews.net/articles/doe-unveils-critical-grid-corridors-for-biden-climate-goals/>; Peter Behr, *More, More, More: Biden's clean grid hinges on power lines*, Energywire, May 23, 2022 (stating that "the Biden administration is seeking an unprecedented expansion of high-voltage electric lines to open new paths to wind and solar energy. 'We obviously need more, more, more transmission to run on 100 percent clean energy . . .,' Energy Secretary

does not deserve a shred of deference under *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*⁹ in any form. Today's final rule is much less the product of reasoned decision-making or the agency's specialized expertise, as of political pressure and special interest lobbying.¹⁰ In the chapter on "regulatory capture"¹¹ in future economics textbooks, today's final rule should be a featured case study.

4. The final rule orders *all* transmission providers, RTO and non-RTO, to plan costly regional transmission for some *allegedly* predictable generation mix 20 years in the future (a generation mix which, as a practical matter, is impossible to predict so far into the future).¹² The obviously pretextual agenda of

Jennifer Granholm said in February.") (emphasis added), <https://subscriber.politicopro.com/article/eenews/2022/05/23/more-more-more-bidens-clean-grid-hinges-on-power-lines-00030117>; see also *supra* n.5 and *infra* nn.10, 13, 15, 16, 67.

⁹ 467 U.S. 837 (1984) (*Chevron*).

¹⁰ See Catherine Morehouse, *FERC to tackle "historic" transmission planning rule in May*, PoliticoPRO, Apr. 18, 2024 ("FERC has been under enormous pressure from lawmakers, clean energy developers, environmentalists and others to finalize the rule that Chair Willie Phillips has promised will be 'historic' and the 'greatest development regarding electric transmission rules in the country in over a generation.'") (emphases added), <https://subscriber.politicopro.com/article/2024/04/ferc-to-tackle-massive-transmission-planning-rule-next-month-00153191>; see also, e.g., Sen. Charles E. Schumer July 24, 2023 Comments at 1–2 (urging the Commission to ensure that "any final rule must . . . prescribe a set of benefits" to be used in transmission planning and that "it will be necessary that either" [the transmission provider, or FERC shall impose cost allocation] "when any state withholds support on a cost allocation method" [which risks] "states that benefit from a transmission line" [acting as] "free riders [to] avoid any costs.") (emphases added); Sen. Martin Heinrich, et al. (consisting of 20 additional Senators) Jan. 19, 2024 Comments at 2 (urging the Commission that "the final rule must require consideration of a . . . specific set of transmission benefits for . . . cost allocation processes") (emphases added); Sen. Sheldon Whitehouse Nov. 7, 2023 Comments at 2 (stating that "FERC should include [a list of required benefits] in its final rule"). As explained extensively herein, mandating benefits is a device for imposing costs on consumers in states that never agreed to the selection criteria or cost allocation. The deeply granular nature of the instructions to the Commission in these letters is more evidence that this final rule is a pretext to use an administrative agency to enact legislation that Congress never passed. See also *supra* nn.5, 8 and *infra* nn.13, 15, 16, 67.

¹¹ Luigi Zingales, *Preventing Economists' Capture*, University of Chicago Booth School of Business Review, July 1, 2014 ("In simple words, regulatory capture exists when a regulatory agency, created to act in the public interest, ends up advancing interests of the industry it is charged with regulating."), <https://www.chicagobooth.edu/review/preventing-economists-capture>.

¹² The example of the Potomac-Appalachian Transmission Highline (PATH) fiasco is a strong warning about the folly of spending billions of consumers' dollars to build transmission based on predictions of a generation mix in 20 years. *Potomac-Appalachian Transmission Highline, LLC*, 185 FERC ¶ 61,198 (2023) (Christie, Comm'r, concurring at P 3) (PATH Concurrence) ("[C]onsumers have paid roughly \$250 million for a project that was never built nor found needed by a single state regulator.") (emphasis in original),

the final rule, however, is not to *predict* the generation mix 20 years forward, but to *produce* the *preferred* generation mix that the current presidential administration, some huge multinational corporations,¹³ some members of Congress, and other special interests want *now*. In fact, the final rule is not even about planning *transmission*, but is about planning *policy*, and it is very preferential about the policies it wants to promote. As with the Great Oz,¹⁴ pulling back the curtain exposes the final rule for what it really is: An essential component in a comprehensive plan by the current presidential administration to push what the media describe as "green policies" designed to prefer and promote the wind and solar generation it favors while simultaneously *forcing* the shutdown of the fossil fuel generation it disfavors,¹⁵ both needed to meet

<https://www.ferc.gov/news-events/news/e-4-commissioner-christies-concurrence-letter-order-approving-path-settlement-er12>; see also PJM Initial Comments at 62 ("In short, the volatility of input parameters cancelled the need for a \$1.8 billion transmission line identified in 2007, that was confirmed to be needed five years out in 2012, but by 2012 was no longer needed for at least another 15 years, if at all."). Rather than wind or solar—which the final rule implicitly presumes will be the predominant generating resource in 20 years—it is just as foreseeable that the predominant share of generation in the U.S. could be nuclear, an essential dispatchable resource, as small modular reactor technology matures and economies of scale produce lower costs, or it could be green hydrogen. It could even be fusion or some new technology currently either nascent or unknown. *No one knows today*. Building trillions of dollars of transmission on a *prediction* that intermittent wind and solar will be the predominant generating resource in 20 years is just a costly guess.

¹³ See, e.g., Clean Energy Buyers Jan. 22, 2024 Comments ("Many of our businesses cannot grow without more *clean generation* resources States may miss out on economic growth opportunities without . . . access to the *types of generation resources* needed to attract growing and innovative industries.") (emphases added). Among the signers of these comments were Amazon, Apple, eBay, Google, Green Impact Technologies, Meta, Microsoft, Nike, Rivian, Salesforce, Target, Walmart and several other multinational corporations. The FPA gives FERC no authority whatsoever to use the "green energy" purchasing preferences of privately owned, for-profit multinational corporations as the basis to impose a *mandatory* transmission planning and cost allocation rule that will cost consumers trillions of dollars. The FPA does not recognize such corporate preferences; indeed, the FPA *forbids* preferences. See also *supra* nn.5, 8, 10 and *infra* nn.15, 16, 67.

¹⁴ *The Wizard of Oz* (Metro-Goldwyn-Mayer 1939).

¹⁵ See, e.g., Catherine Morehouse, *DOE launches effort to cut federal permitting for new power lines in half*, PoliticoPRO, Apr. 25, 2024 ("The [U.S. Dept. of Energy] program is the latest move by the Biden administration to speed up the . . . process for new transmission lines deemed critical to carrying dispersed wind and solar resources It also comes on the heels of an announcement from the EPA to tighten emissions standards for fossil-fueled power plants—a move that will necessitate bringing more low-carbon resources onto the power grid to meet growing demand as [fossil fuel] resources are forced offline. 'DOE's work complements what our partners across the administration are doing . . . to deliver cleaner power . . . ,' Energy Secretary Jennifer Granholm told reporters . . .") (emphases added), <https://>

its political commitment. Let me emphasize: Whether the policies being promoted in this final rule can be described as "green, purple, red or blue" is irrelevant. The point is that FERC, as an *independent* agency, has no business promoting the policies of any one party or presidential administration, especially when, as here, the effort to do so goes far beyond FERC's legal authority and fails to perform our consumer protection function under the FPA.

5. Yet here's the legal rub with the final rule's pretextual agenda: *Congress never voted to amend the FPA to direct or even allow* FERC (which is supposed to be *independent*) to be what Energy Secretary Granholm describes as one of "our partners across the administration" in implementing this "green energy" transformation agenda.¹⁶ Such a sweeping policy agenda, which involves the transfer of literally *trillions* of dollars of wealth from consumers to special interests, is the epitome of a major question

subscriber.politicopro.com/article/2024/04/doe-launches-effort-to-cut-federal-permitting-for-new-power-lines-in-half-00154189; see also Catherine Morehouse, *Energy regulator's exit may flummox Biden's green plans*, Politico, Feb. 9, 2024 ("[FERC] is poised to lose its biggest climate advocate and potentially shut down one of the White House's best avenues to push its green policies. . . . That buildout is needed to accommodate . . . wind and solar projects that are critical to meeting the Biden administration's climate and clean energy goals.") (emphases added), <https://subscriber.politicopro.com/article/2024/02/energy-regulators-exit-may-flummox-bidens-green-plans-00140774>; Molly Christian, *US transmission "in desperate need of an upgrade," Vice President Harris says*, Megawatt Daily, Jan. 20, 2023 ("Achieving lofty US climate goals will require 'thousands of miles of new high-voltage transmission lines all across our country,' US Vice President Kamala Harris said 'To create our clean energy future, we must construct thousands of miles of new high-voltage transmission lines all across our country,' [Harris said].") (emphases added), <https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/012023-us-transmission-in-desperate-need-of-an-upgrade-vice-president-harris-says>; Alex Guillén, Ben Lefebvre, Annie Snider, Kelsey Tamborrino, Catherine Morehouse, James Bikales, *Biden administration eyes spring to finalize key climate regulations*, PoliticoPRO, Dec. 6, 2023 ("The Biden administration is planning to finalize several major energy and environmental regulations in the first half of 2024 That timeframe would help cement many of President Joe Biden's policy priorities in the event he does not win reelection One of the top [FERC] priorities . . . has been to finalize a rule on power line planning and cost allocation that is considered critical to unlocking new wind and solar resources.") (emphases added), <https://subscriber.politicopro.com/article/2023/12/biden-administration-plots-busy-spring-finalizing-key-climate-regulations-00130496>. See also *supra* nn.5, 8, 10, 13 and *infra* nn.16, 67.

¹⁶ See Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines*, The New York Times, Apr. 25, 2024 ("[Biden] Administration officials are increasingly worried that their plans to fight climate change could falter unless the nation can quickly add vast amounts of grid capacity to handle more wind and solar power But experts say a rapid, large-scale expansion may ultimately depend on Congress.") (emphases added), <https://www.nytimes.com/2024/04/25/climate/energy-dept-speed-transmission.html>. See also *supra* nn.5, 8, 10, 13, 15 and *infra* n.67.

of public policy under *West Virginia v. EPA*. The final rule clearly intends to socialize trillions of dollars of costs for the transmission necessary to pursue this transformational agenda, and unlike the NOPR,¹⁷ the final rule removes the principle that the states must consent to how and whether these massive costs are imposed on their consumers. The final rule goes to great lengths to use “nothing to see here” rhetoric,¹⁸ but looking behind the curtain at what is really going on makes it obvious that the final rule is pretextual and a blatant violation of the major questions doctrine.¹⁹ In its transparent effort to plan and fund trillions of dollars’ worth of transmission to facilitate a *preferred* generation mix predominantly of wind and solar, both for public policies as well as corporate purchasing preferences, it is also “preferential” and thus a clear violation of FPA section 206.

6. Put most simply, the final rule is a shell game that plays this way:

Step One: For planning and cost allocation purposes, throw transmission projects that solve specific reliability problems or reduce congestion costs into the same bucket as projects designed to promote public policies or corporate “green energy” preferences and disguise the purpose of very different projects by re-labeling *all* projects in the new bucket with the innocuous-sounding name “Long-Term Regional Transmission Facilities.”

Step Two: Mandate planning inputs that must be used in determining which projects get selected for regional plans, which starts the money flowing from consumers to developers before any state has even evaluated the need for, or cost of, the projects.

Step Three: Mandate benefits that will ultimately affect the allocation of costs to consumers across a multi-state region. Combined with Steps One and Two, this

makes consumers involuntary “beneficiaries” who will then be forced to pay for projects that promote another state’s public policy or corporate “green power” commitments.

Step Four: Order all transmission providers to develop and file a cost allocation formula that will automatically be the default applicable to the entire bucket of Long-Term Regional Transmission Facilities.

Step Five: Remove the NOPR’s requirement that states must consent to the details of Steps One through Four before their consumers can be burdened with costs.

7. Let’s drill down on the details of the final rule’s shell game. The final rule seeks to shift the costs of transmission projects whose purpose is to implement state or local public policies promoting wind and solar generation (commonly referred to as “public policy projects” or “policy-driven projects”) and big corporation “green energy” preferences by putting those projects into the same regulatory bucket—both for planning *and* cost-allocation purposes—with fundamentally different types of projects, those designed either to solve identified *reliability* problems (an engineering purpose, not a political or corporate purpose) or to provide quantifiable congestion cost savings (*economic* projects).²⁰ The final rule labels *all* projects thrown into the new bucket as “Long-Term Regional Transmission Facilities.”²¹ Lumping policy-driven projects with the other very different types of projects is a sleight-of-hand move to disguise the costs of the policy-driven and corporate-driven projects that the final rule is promoting.²² Put most simply, reliability

projects are driven by engineering, economic projects by economics, public policy projects by politicians, and corporate “green energy” policies by management and investors looking to maximize their returns or satisfy investment goals not recognized by the FPA.

8. Then to further promote its preferred policy projects, the final rule mandates planning criteria to be used in the planning of Long-Term Regional Transmission Facilities,²³ including the “categories of factors” that must be used in developing long-term planning scenarios²⁴ and the list of benefits that must be used by planners in cost-benefit analyses.²⁵ All of these mandatory features are transparently intended to “pre-cook” outcomes by manipulating the planning and evaluations that determine which projects are selected for regional transmission plans. (It is emblematic of the entire final rule that it did *not* include “saves retail customers money” as one of its mandatory benefits for evaluating projects.)²⁶ The shell game’s purpose is to ensure that preferential policy and corporate-driven projects are selected for regional transmission plans, which conveniently ensures that such projects are eligible for cost recovery through FERC’s very generous (to developers, not consumers) formula rate mechanism. As further proof of the nature of the shell game, the final rule does not require transmission providers to identify the benefits used (other than those mandated), or how those benefits were specifically calculated, for cost allocation purposes.²⁷ While the final rule insists that it is not mandating *outcomes*, when you manipulate the *inputs* of transmission planning, you are effectively mandating outputs.²⁸

9. But that’s not all; here comes the worst part of the shell game. The final rule then requires every transmission provider in America to file an *ex ante* cost allocation formula that is applicable to the whole bucket of projects,²⁹ which now includes public and corporate-driven policy projects, *in order to socialize the costs of these projects across the entire region, even when states in a region have never consented for their consumers to bear the costs of such projects*. The final rule seeks to justify this

are allocated by PJM proportionately to each component of the project, one percentage allocated as a reliability project under PJM’s formula, the other percentage wholly allocated to New Jersey for the SAA project.” (internal citation omitted).

²³ Final Rule, 187 FERC ¶ 61,068 at Section III.

²⁴ *Id.* P 409. Among the *mandatory* categories of factors that the final rule dictates must be used to drive long-term planning throughout the entire country are, *inter alia*: (i) *state and local laws affecting the resource mix*, (ii) *state and local laws on decarbonization*, (iii) *generator interconnection requests and withdrawals* (another way to subsidize and prefer wind and solar developers which dominate the queues), and (iv) *corporate, state and local government commitments to purchase “green” energy*. Let me emphasize: these planning factors are *mandatory* for transmission providers to use, exposing the final rule’s pretextual agenda for what it really is.

²⁵ *Id.* PP 3, 269, 719–720.

²⁶ *See, e.g., id.* P 720.

²⁷ *Id.* PP 1505–1511.

²⁸ *Id.* P 965.

²⁹ *Id.* P 1291.

¹⁷ *Bldg. for the Future Through Elec. Reg’l Transmission Planning & Cost Allocation & Generator Interconnection*, Notice of Proposed Rulemaking, 87 FR 26504 (May 4, 2022), 179 FERC ¶ 61,028, at P 303 (2022) (NOPR).

¹⁸ *See, e.g.,* Final Rule, 187 FERC ¶ 61,068 at P 265 (“[W]hat matters is that this final rule aims to regulate and, in fact, does regulate only practices that affect the transmission of electric energy in interstate commerce, which are squarely within the Commission’s jurisdiction under the FPA.”).

¹⁹ *See infra* Section III.C. The final rule insists that it most assuredly does *not* implicate a major question of public policy, Final Rule, 187 FERC ¶ 61,068 at PP 275–279, much like Captain Renault in *Casablanca* is “shocked, shocked to find gambling going on in here” as he pockets his winnings. *Casablanca* (Warner Bros. Pictures 1942); but see Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines*, Apr. 25, 2024 (quoting Rob Gramlich, the president of the consulting group Grid Strategies, “‘I’ve called [the final] rule the biggest energy policy in the country.’”) (emphasis added), <https://www.nytimes.com/2024/04/25/climate/energy-dept-speed-transmission.html>. *See* Catherine Morehouse, *FERC to tackle “historic” transmission planning rule in May*, PoliticoPRO, Apr. 18, 2024 (quoting Chairman Phillips describing the final rule as “historic” and the “greatest development regarding electric transmission rules in the country in over a generation . . .”) (emphases added).

²⁰ *See, e.g.,* Final Rule, 187 FERC ¶ 61,068 at PP 1474 (“[T]ransmission providers may not establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may not establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types.”).

²¹ *Id.*; *see also id.* PP 41, 250–251. In terms of labeling, at least Order No. 1000 described public policy projects honestly, as those that address “transmission needs driven by Public Policy Requirements.” *See, e.g.,* *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051, at PP 2, 6 (2011), *order on reh’g*, Order No. 1000–A, 139 FERC ¶ 61,132, *order on reh’g & clarification*, Order No. 1000–B, 141 FERC ¶ 61,044 (2012), *aff’d sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (*South Carolina*); *see also id.* PP 11, 47.

²² *See PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,012 (2024) (Christie, Comm’r, concurring at P 6 n.12) (“I note too that in PJM’s [Regional Transmission Expansion Plan (RTEP)] review it offers a good example of how components of two different types of projects, a specific reliability solution and [State Agreement Approach (SAA)] Project, can be combined into one project that meets both needs. PJM describes in its filing how it solved a Window 3 specific reliability problem by combining that solution with an SAA project into an Incremental Multi-Driver Project This is a good example of how a multi-driver project should work: The reliability need is specific and would require a specific reliability solution that would, on its own, merit inclusion in the RTEP as a reliability project, and the SAA project, which is a supplemental—not a reliability—project, if feasible as it is in this specific case, can be planned in a way to meet the specific reliability need. Costs

imposition of costs on non-consenting states by treating their consumers as “cost causers” or “beneficiaries,”³⁰ which is justified by—now circle back to earlier in the shell game—the final rule’s imposition of mandatory factors and benefits that must be used in the evaluations of projects.³¹ By lumping reliability and economic projects into the same planning bucket as public and corporate-driven policy projects, the final rule seeks to affix the tags of “cost causer” and “beneficiary” to *all* consumers in a multi-state region, to justify sticking them with costs even if their state officials never consented. So despite the final rule’s disingenuous claims to the contrary,³² the intent and effect of this shell game is to enable the costs of corporate and public policy-driven projects to be socialized across an entire multi-state region and thus shifted onto consumers in states that never agreed to bear such costs. The *explicit* promise of the NOPR, that states would have to *consent* for their consumers to bear such costs, has been broken in this final rule.

10. When I voted for the NOPR, I made it absolutely clear I was voting for it because it reflected a *compromise* in which public and corporate policy-driven projects could be incorporated into long-term planning, but *only if* the states had the authority to consent *both* to planning criteria, including benefits used in cost-benefit analyses to evaluate

projects and selection criteria, as well as to cost allocation.³³ In my concurrence to the NOPR I wrote:

Even more importantly though, for these [long-term] projects, the NOPR proposes to *require* the regional planning entities to consult with and *seek the agreement of the relevant states to both the selection criteria for these projects and to the regional cost allocation arrangements. State approval is especially important in a multi-state region, where different states have different policies.* The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements. States can agree to an *ex ante* formula for regional cost allocation of these types of projects—such as, for example, the “highway-byway” formula approved by the SPP Regional State Committee—or states can agree to a process for a project-by-project agreement on cost allocation among one or several states—such as, for example, the State Agreement Approach in PJM—or states may choose some combination of both.³⁴

And let me emphasize . . . *no individual state’s consumers can be forced to bear the costs of another state’s policy-driven project or element of a project against its consent.*³⁵

The bottom line for me is this: I believe that elevating the role in planning and cost allocation of state regulators—who are, as a group, deeply concerned about the monthly bills paid by consumers, of which transmission is a rapidly growing component—will make it *more likely, not less*, that necessary transmission can get built while ensuring that rates resulting from these types of policy-driven projects will not be *unjust and unreasonable, which they clearly have the potential to be.*³⁶

The other members of the Commission, including the then-Chairman and both other members of today’s Commission, also recognized the NOPR as a compromise.³⁷

³⁰ See, e.g., *id.* P 1305 n.2786 (“The cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits.”) (emphasis added). A true statement on its face, but utterly disingenuous here. By mandating its preferred factors to be used in long-term planning, by mandating certain benefits to be used in evaluating projects, and by denying transparency as to what other benefits are used to evaluate projects and *how* benefits are being calculated, which drives cost allocation, the final rule effectively will hide the specific costs of policy and corporate-driven projects and essential information as to how costs are being calculated and allocated across a multi-state region. See also *supra* n.10.

³¹ These key elements of the shell game respond almost precisely to the lobbying demands of various interest groups. See, e.g., Environmental Groups Dec. 8, 2023 Comments (“Transmission providers must perform long-term (at least 20-year), forward-looking assessments . . . They must . . . [include] planning for state clean energy laws and policies, [and] scenarios with high renewable penetration . . . Scenarios must evaluate all benefits that transmission projects would deliver and use these assessed benefits as a basis for project selection . . . The Commission also should create a default cost allocation policy that meets this same standard . . .”) (emphases added). Among others, the signers of this letter include: Advanced Energy United, American Clean Power Association, Clean Air Task Force, Earthjustice, Environmental Defense Fund, Evergreen Action, League of Conservation Voters, National Wildlife Federation, Natural Resources Defense Council (NRDC), Sierra Club, Union of Concerned Scientists, and WE ACT for Environmental Justice. See also *supra* nn.8, 10.

³² Final Rule, 187 FERC ¶ 61,068 at P 267 (“[N]othing in this final rule requires states to subsidize other states’ public policies and, indeed, this final rule requires . . . that transmission customers within a transmission planning region need only pay costs that are ‘roughly commensurate’ with the benefits that *transmission providers estimate* they will receive from a transmission facility.”) (emphasis added).

³³ NOPR, 179 FERC ¶ 61,028 (Christie, Comm’r, concurring at PP 11–12, 14) (NOPR Concurrence); see also *id.* P 5.

³⁴ *Id.* P 11 (emphasis in original and added).

³⁵ *Id.* P 12 (emphasis added).

³⁶ *Id.* P 14 (emphasis in original and added).

³⁷ From the Transcript of Apr. 21, 2022 Commission Open Meeting (April 2022 Open Meeting Tr.):

“CHAIRMAN GLICK: And I also want to finally thank my colleagues. I think this [NOPR] is a *really good product*. It is a product of a lot of discussion, a lot of compromise—which is what the Commission is all about—and I think *all of us can say we did not get everything in there, in the document, that we would like, but I think we all got enough in there and I think we achieved a significant and really remarkable level of consensus*. And I think that is very notable today.” April 2022 Open Meeting Tr. 44:17–24 (emphases added).

“COMMISSIONER CLEMENTS: As the Chairman [stated] that reaching agreement on this proposal was not easy, I can say with confidence that *none of us voting for it would have written it this way if we were writing on our own. But I am proud that it is a bipartisan effort*, and I am thankful to my colleagues for proactively engaging and for thinking creatively to find alignment.” *Id.* at 55:17–23 (emphasis added).

11. Yet the many fundamental changes made in this final rule³⁸ subvert and violate that compromise. Of particular importance to my willingness—and that of many state regulator organizations—to support the compromise NOPR, was the explicit principle of state agreement to planning and selection criteria and cost allocation embodied in the NOPR. The final rule, however, *denies what the NOPR promised*: it denies state agreement to selection criteria,³⁹ it denies state agreement to the benefits to be used in evaluating projects for selection in regional plans and ultimate selection (which can start the money flowing from consumers to developers before a state siting or construction permit has even been issued),⁴⁰ and most importantly, it denies state agreement to cost allocation for public policy and corporate-driven projects.⁴¹ The State Agreement Approach, used successfully in PJM for over a decade, is effectively terminated by the final rule. The final rule says that, *even if states in a planning region agree*, a “State Agreement Process” *cannot* be the sole chosen method for allocating costs of these projects; the transmission provider’s own *ex ante* formula *must* be the default method, regardless of whether states have agreed to it.⁴² In addition to a *de facto* termination of the PJM State Agreement Approach, the final rule could call into question mechanisms to facilitate the states’ role in cost allocation that have been used in other RTOs and ISOs for years, including in SPP and MISO.⁴³

12. And let’s get real: Telling the states to negotiate for an alternative cost allocation when the transmission provider’s *ex ante* formula has already been designated as the default is no real negotiation at all. The final rule points a regulatory gun at states’ heads redolent of *The Godfather*:⁴⁴ “Here’s an offer

“COMMISSIONER CHRISTIE: But I think on balance the positive aspects of this [NOPR], particularly for state regulators at the heart of planning and cost allocation for these types of projects, changing [CWIP] to AFUDC[,] I think those are *positive, big steps forward for me on balance and it makes it worth voting for this [NOPR].*” *Id.* at 67:15–20 (emphasis added).

“COMMISSIONER PHILLIPS: I would first like to thank my colleagues for working collaboratively with me on this. . . . I don’t think I have ever been a part of a process more collaborative than this process that we had in this NOPR.” *Id.* at 67:24–25, 68:6–8.

To those who say that many elements of this final rule were also in the NOPR for which I voted, such as, for example, the mandatory categories of factors, I would respond: If I agree to get a root canal with anesthetic, but learn upon arrival at the dentist’s office that I can still get the root canal but with no anesthetic, that is not the original deal.

³⁸ See *infra* Section II.

³⁹ Final Rule, 187 FERC ¶ 61,068 at P 996.

⁴⁰ *Id.* PP 3, 269, 719–720, 903.

⁴¹ *Id.* PP 1291–1292, 1294, 1354, 1356 n.2895, 1359, 1367, 1429.

⁴² *Id.* To be clear, even if the states agreed on an alternative *ex ante* cost allocation method, or if they agreed on a cost allocation method under the State Agreement Process, the transmission provider could choose to file it but also *could ignore it*. See *infra* n.195.

⁴³ See Final Rule, 187 FERC ¶ 61,068 at PP 1291–1292, 1294, 1354, 1356 n.2895, 1359, 1367, 1429.

⁴⁴ *The Godfather* (Paramount 1972).

you can't refuse." And contrary to NARUC's eminently reasonable and practical request,⁴⁵ the final rule even requires only one Engagement Period for states to negotiate a different cost allocation from the transmission providers' *ex ante* cost allocation before that *ex ante* cost allocation becomes the default.⁴⁶ It is obvious that the final rule intends to lock in each transmission provider's own *ex ante* formula for many years to come and to deny states any avenue to challenge it even as times and circumstances change, no matter how high their consumers' power bills escalate due to rising transmission costs.

13. Essentially, the final rule replaces the NOPR's principle of requiring state agreement to selection criteria, benefits, and cost allocation with a charade of suggesting to transmission providers that they "consult with and seek support" from the states—while paradoxically "clarifying" that transmission providers do not actually need to obtain state consent—and the final rule uses other empty phrases such as allowing states to "inform" or "provide input on" the evaluation process and cost allocation.⁴⁷ But the final rule's real attitude towards the states and state regulators is embodied in this airily regal but perhaps unintentionally straightforward pronouncement: "[W]e do not agree that the views of state regulators regarding the appropriate cost allocation approach are dispositive."⁴⁸

14. The principle of cost allocation that was described in my concurrence to the NOPR—that states must consent to regional cost allocation of corporate and public policy-driven projects—reflects a core principle of American democracy: *fairness*. In this ratemaking context, fairness means that the people have the right to choose the policymakers who impose costs on them, so they can hold them accountable. This final rule is *unfair* because it gives FERC and the transmission providers it regulates the power to *impose* costs on consumers to pay for transmission driven by huge corporations and politicians in states other than theirs, and for whom they never voted. The final rule truly subverts the principle that the people, through their state's policymakers, must consent to bear the costs of another state's politicians and their policy choices, or the energy purchasing preferences of corporate managers and investors.

15. And from the consumer standpoint, the timing of this rule could not be worse. American residential customers will pay about 16.23 cents per kWh next year, the

*highest retail power cost for consumers in almost three decades.*⁴⁹ Unlike in years past, fuel costs are not the primary driver of these mounting prices to consumers; rather, transmission is. Transmission costs are rising rapidly, becoming an ever more burdensome part of consumers' power bills.⁵⁰ To cite just one major example, in PJM, the largest RTO by load in the country, the transmission component of wholesale power costs has essentially *tripled* over the past decade, from just \$5.65/MWh in 2013 to \$16.54/MWh last year. Transmission now constitutes almost a third of wholesale power costs, up from approximately 10% just a decade earlier.⁵¹ In 2020, the PJM Market Monitor reported that the cost of transmission exceeded the cost of capacity for the first time.⁵² Nationally, transmission rate base nearly tripled in a decade,⁵³ and—assuming an 8.2% year-over-

⁴⁹ See Robert Walton, *U.S. electricity prices outpace annual inflation*, Utility Dive, Mar. 13, 2024 ("U.S. electricity prices rose 3.6% over the last 12 months, outstripping the broader inflation rate of 3.2%, the Bureau of Labor Statistics reported Tuesday. And experts say there is little chance for near-term consumer relief. . . . And federal policies aimed at electrifying end uses and reducing emissions could lead to even higher prices, Travis Fisher, director of energy and environmental policy studies at the Cato Institute, told a House subcommittee Wednesday.") (emphasis added), <https://www.utilitydive.com/news/us-electricity-prices-rise-customer-eia-outlook/710113/>.

⁵⁰ See, e.g., Zach Bright, *Electricity prices rise faster than inflation*, *EnergyWire*, Apr. 12, 2024 ("The Bureau of Labor Statistics found that electricity prices rose 5 percent over the past year. That's higher than the overall consumer price index (3.5 percent) and any other single commodity, like food . . . and gasoline . . .") (emphases added), <https://www.eenews.net/articles/electricity-prices-rise-faster-than-inflation/>; *Electricity Inflation 30% Higher Than CPI Over Last 12 Months* Electricity Transmission Competition Coalition, Apr. 10, 2024 ("Electricity inflation remains the highest consumer goods cost among the items in the Consumer Price Index according to the latest release of data by the Bureau of Labor Statistics. . . . The price of electricity has soared because of the accelerating cost of transmission . . .") (emphasis added), <https://electricitytransmissioncompetitioncoalition.org/electricity-inflation-30-higher-than-cpi-over-last-12-months/>.

⁵¹ State of the Market Report 2023, PJM Market Monitor, Vol. II, Section 1, at 18, Table 1–9, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023.shtml; State of the Market Report 2014, PJM Market Monitor, Vol. II, Section 1, at 16, Table 1–9, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2-sec1.pdf; State of the Market Report 2013, PJM Market Monitor, Vol. II, Section 1, at 12, Table 1–9, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume2-sec1.pdf; see also State of the Market Report 2019, PJM Market Monitor, Vol. II, Section 1, at 18, Table 1–10, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-sec1.pdf.

⁵² State of the Market Report 2020, PJM Market Monitor, Vol. I, at 17, Table 8, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-vol1.pdf.

⁵³ See Jim O'Reilly, *Led by AEP and Duke, transmission growth poised to rebound from dip in 2022*, S&P Global Market Intelligence, Nov. 15, 2023 (showing bar graph providing that aggregate transmission rate base grew from \$61.4 billion in 2012 to \$163.1 billion in 2022), <https://www.spglobal.com/marketintelligence/en/news->

year growth rate, which occurred in 2022—is on track to double again in the next nine years, even without this rule's intent to spend trillions more on transmission. According to the U.S. Energy Information Administration, already one in three American households reports difficulty in paying their power bills.⁵⁴

16. Don't fall for the absurd claim that this rule will somehow save consumers money through more holistic or efficient planning, a vacuous bureaucratic argument divorced from reality.⁵⁵ The sheer amount of new transmission costs that the final rule inflicts on consumers—and special interest groups want—is staggering, measured in the *trillions*,⁵⁶ not 'merely' hundreds of billions, of dollars.⁵⁷ And these staggering costs will not be incurred to provide consumers with reliable power, but to serve political and corporate agendas. It is truly Orwellian newspeak⁵⁸ to claim that adding multiple trillions of dollars in transmission costs to consumer's bills will somehow "save" consumers money (even Orwell would be impressed at the sheer audacity of such a claim).

17. If FERC were seriously interested in saving consumers' money, it would be acting to rein in the wide array of transmission incentives regularly handed out to transmission developers that are direct transfers of wealth from consumers to developers (long known as "FERC candy"),⁵⁹

insights/research/led-by-aep-and-duke-transmission-growth-poised-to-rebound-from-dip-in-2022. Under this Commission's rate recovery protocols, the transmission owner gets to collect the annual costs of transmission depreciation from rate base, plus a profit, known as Return on Equity, or "ROE," often inflated by the many incentives the Commission typically approves, as well as operations and maintenance costs. As any utility regulator knows, "what goes into rate base comes out in customers' bills." So a rapidly rising rate base means rapidly growing consumers bills.

⁵⁴ Amanda Durish Cook & Tom Kleckner, *Overheard at 10th Annual GCPA MISO-SPP Forum*, RTO Insider, Mar. 12, 2024, <https://www.rtoinsider.com/73311-overheard-10th-annual-gcpa-miso-spp-forum/>.

⁵⁵ See, e.g., Final Rule, 187 FERC ¶ 61,068 at P 89.

⁵⁶ See *supra* n.7.

⁵⁷ Illinois Senator Everett Dirksen is said to have once quipped, "In Washington, a billion here, a billion there, and pretty soon you're talking about real money." The final rule updates his quip to a "trillion here, a trillion there"

⁵⁸ George Orwell, 1984 (first published by Secker & Warburg 1949).

⁵⁹ See, e.g., *Office of Ohio Consumers' Counsel v. Am. Elec. Power Serv. Corp.*, 181 FERC ¶ 61,214 (2022) (Christie, Comm'r, concurring at P 2), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-addressing-rto-adders-related-e-2-ohio>; MISO, 181 FERC ¶ 61,094 (2022) (Christie, Comm'r, concurring at P 2), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-urging-action-re-rto-participation-adder-docket>; Mary O'Driscoll, *FERC approves incentives for AEP, Allegheny grid projects*, *Greenwire*, July 21, 2006 ("The approvals came as the commission finalized rules intended to promote transmission-grid additions that outline specific rate and other incentives that FERC will consider for future construction projects—the 'FERC candy' that critics contend gives the utilities incentives but not much in the way of corresponding requirements.") (emphasis added),

⁴⁵ Final Rule, 187 FERC ¶ 61,068 at P 1255 ("NARUC requests that the Commission provide a mechanism for future review of cost allocation methods for Long-Term Regional Facilities." (citing NARUC Initial Comments at 49–50)).

⁴⁶ *Id.* P 1368; see also *id.* P 1291.

⁴⁷ See, e.g., *id.* PP 268, 959, 994, 996–997, 1456.

⁴⁸ *Id.* P 1363 (citation omitted). A different attitude towards state regulators was apparent in the NOPR. See April 2022 Open Meeting Tr. 46:10–16 ("CHAIRMAN GLICK: [This] NOPR proposes to give the states a much more significant role in addressing cost allocation. I think it helps to have Commissioner Christie and Commissioner Phillips, two of our five Commissioners are former state regulators, and I think that really helps to have their background and their interest.").

and acting to reform the automatic awarding of the presumption of prudence in formula rate proceedings. Literally *nothing* is being done about these forms of consumer exploitation in this final rule; instead, the final rule goes in the exact opposite direction.

18. To add further insult to consumers' injury, the final rule *walks back* the NOPR proposal that would have denied transmission developers the Construction Work in Progress (CWIP) incentive.⁶⁰ I have written many times that CWIP is simply unfair. CWIP is unfair because it makes consumers the unwilling "bank" for developers, but unlike a real bank, consumers don't get paid any interest and this Commission forces them to make involuntary loans.⁶¹ Removing CWIP was

strongly supported by those concerned with protecting consumers: by state regulators, by public power providers, and by state consumer advocates.

19. In my concurrence to the NOPR, I wrote:

CWIP is the award of cost recovery of construction costs during the pre-construction and construction phases to the developer. CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer. . . . Consumers should be protected from paying CWIP costs during this potentially long period before a project actually enters service, if it ever does. *This NOPR proposal represents a major step forward in consumer protection and is a big reason I am voting for it.*⁶²

By walking back the proposed CWIP denial, the final rule results in a *major step backwards* for consumers.⁶³

20. In yet another major slap at consumers, the final rule seeks to shift the substantial costs caused by generation developers' interconnection requests from developers to consumers.⁶⁴ It does this by ordering transmission providers to revise their regional transmission planning processes to evaluate for selection regional transmission facilities that address identified interconnection-related transmission needs, and the final rule specifies that if such a facility is selected, *its costs will be regionally allocated*.⁶⁵ It also does this by ordering transmission providers to incorporate generator interconnection requests and withdrawals in their long-term transmission

planning.⁶⁶ These are only schemes to shift interconnection costs from developers to consumers and will result in rates that are blatantly unjust, unreasonable, unduly discriminatory and preferential. Similarly, the final rule also inappropriately shifts preferential corporate-driven project costs onto *all* other consumers, who may disagree with, or even compete against, the corporate customers imposing their preferences. These provisions alone render the final rule's replacement rate unlawful under FPA section 206.

21. This Commission is, by statute, supposed to be *independent* of any presidential administration, but it has failed to defend that independence in this final rule, which is a naked pretext to enact the current administration's "net zero 2035" policy agenda, as well as to serve corporate agendas, and those of other profit-seeking special interests.⁶⁷ In failing to act independently,⁶⁸ this Commission has broken faith with state regulators and, even more importantly, broken faith with tens of millions of American consumers, who could be forced to bear literally trillions of dollars in costs for transmission lines to serve political, corporate and other special-interest agendas. This will not produce just and reasonable rates and is grossly unfair. This final rule is a dereliction of the Commission's duty under the FPA to protect consumers and far exceeds its authority under that statute.

II. The Final Rule Is Fundamentally Different From the NOPR

22. The very essence of due process is notice and opportunity to be heard. Given the large number of fundamental changes to the NOPR, the final rule should be viewed as effectively a second NOPR and clearly should have been put out for additional public comment on the many fundamental changes. Because it was not, deliberately so, this final rule invites a court to remand with instructions for the Commission to give the public an opportunity to comment on the many fundamental changes from the NOPR.

23. The final rule issuing today is not the NOPR for which I voted. This pretextual final

<https://subscriber.politicopro.com/article/eenews/2006/07/21/ferc-approves-incentives-for-aep-allegheeny-grid-projects-234508>.

⁶⁰ Final Rule, 187 FERC ¶ 61,068 at P 1547.

⁶¹ *Baltimore Gas & Elec. Co.*, 187 FERC ¶ 61,030 (2024) (Christie, Comm'r, dissenting at P 7), <https://www.ferc.gov/news-events/news/commissioner-christie-dissent-award-incentives-exelon-er24-1313>; *PJM Interconnection, L.L.C.*, 185 FERC ¶ 61,200 (2023) (Christie, Comm'r, concurring at P 3), <https://www.ferc.gov/news-events/news/e-7-commissioner-christies-concurrence-exelons-application-abandoned-plant>; *The Potomac Edison Co.*, 185 FERC ¶ 61,083 (2023) (Christie, Comm'r, concurring at P 3), <https://www.ferc.gov/news-events/news/e-7-commissioner-christies-concurrence-exelons-application-abandoned-plant>; *Montana-Dakota Utils. Co.*, 185 FERC ¶ 61,015 (2023) (Christie, Comm'r, concurring at P 3), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-indep-sys-operator-inc-0>; *GridLiance W. LLC*, 184 FERC ¶ 61,129 (2023) (Christie, Comm'r, concurring at P 3), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-gridliance-west-regarding-transmission>; *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,136 (2023) (Christie, Comm'r, concurring at P 3), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-indep-sys-operator-inc-0>; *GridLiance W. LLC*, 184 FERC ¶ 61,129 (2023) (Christie, Comm'r, concurring at P 3), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-gridliance-west-regarding-transmission>; *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,136 (2023) (Christie, Comm'r, concurring at P 3), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-midcontinent-indep-sys-operator-inc-0>; *GridLiance W. 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rule is fundamentally different in numerous ways, yet these fundamental changes were never put out for additional public comment.⁶⁹ These fundamental changes include, but are not limited to, the following:

24. *The Final Rule Imposes Preferential Policy and Corporate-Driven Project Costs on Consumers in Non-Consenting States:* Contrary to the NOPR, the final rule requires the filing of one or more *ex ante* cost allocation methods to apply to selected Long-Term Regional Transmission Facilities, setting up a mechanism to impose a regional cost allocation for preferential policy and corporate-driven projects when states do not consent, either by approving a cost allocation proposed by transmission owners, by RTOs, or one directly imposed by the Commission itself.⁷⁰ This is a fundamental change from the NOPR.

25. *The Final Rule Mandates Planning Criteria and Purported Benefits:* Contrary to the NOPR, the final rule mandates a specific set of planning criteria, and specifically purported benefits, that must be used by transmission providers for these preferential policy and corporate-driven projects.⁷¹ Mandating the planning criteria and benefits is simply a way of “pre-cooking” outcomes and is directly contrary to the NOPR’s explicit language that said it was *not* mandating outcomes, only a planning process.⁷² This is a fundamental change from the NOPR.

26. *The Final Rule Abandons Regional Cost Allocation Principle (6):* Contrary to the NOPR,⁷³ the final rule abandons the regional cost allocation principle⁷⁴ that would allow a transmission planning region to use different cost allocation methods for different types of facilities in a regional transmission plan. The final rule replaces this flexibility with a one-size-fits-all model.⁷⁵ This is a fundamental change from the NOPR.

27. *The Final Rule Effectively Eliminates a Voluntary State Agreement Process:* Contrary to the NOPR, the final rule effectively eliminates the use of a voluntary State Agreement Process, such as the one that has been used by PJM since Order No. 1000.⁷⁶ Not only is this directly contrary to comments filed by state regulators,⁷⁷ but it

represents a fundamental change from the NOPR.

28. *The Final Rule Leaves the CWIP Incentive Intact:* Contrary to the NOPR, the final rule walks back the proposal not to allow use of the CWIP incentive.⁷⁸ This NOPR provision was one of the strongest consumer protection features.⁷⁹ Instead, the Commission leaves the CWIP incentive intact and that consumer protection has been removed. This is a fundamental change from the NOPR.

29. *The Final Rule Makes Local Transmission Planning Less Transparent:* Contrary to the NOPR,⁸⁰ the final rule makes fundamental changes to the NOPR’s section on Local Transmission Planning.⁸¹ Local Transmission Planning disclosure and transparency requirements no longer apply to asset management projects. This is a fundamental change from the NOPR.

III. The Final Rule Exceeds FERC’s Authority Under the FPA

30. The final rule’s determination that its reforms are within the Commission’s legal authority under section 206 is flat wrong.⁸² The final rule is just a pretext for enacting the current presidential administration’s “net zero 2035” policy agenda, as well as that of large corporate buyers of preferential power and other special interests.⁸³ As such, the final rule goes far beyond the scope of Order No. 1000, as affirmed by *South Carolina*,⁸⁴ and exceeds FERC’s authority under the FPA. Specifically, the final rule requires transmission providers to incorporate into their transmission planning seven categories of factors and a set of seven required benefits to drive the construction of projects to achieve the final rule’s preferred substantive outcomes: namely, the development and purchase of certain preferred generation resources. In so doing, the final rule seeks to recast FERC as a national IRP planner with extraordinary powers to oversee and dictate to all public utility transmission providers in the country, in RTO and non-RTO regions, detailed instructions on planning transmission that fulfills the current administration’s preferred policies as to the types of generation it wants to build, and to charge consumers trillions of dollars for this transmission. This transformation of FERC into a national IRP planner violates FPA section 201 by infringing on the authority of the states, and it reflects a tremendous expansion of the agency’s power not permitted under the major questions doctrine.

A. South Carolina Does Not Provide a Legal Justification for the Commission’s Actions in the Final Rule

31. In arguing that the Commission is acting within its legal authority under section 206 to adopt its reforms for Long-Term

Regional Transmission Planning, today’s final rule heavily relies on *South Carolina*.⁸⁵ However, given the significant differences between Order No. 1000 and the final rule, that reliance is grossly misplaced.

32. Order No. 1000 included reforms intended to ensure that the transmission planning and cost allocation requirements embodied in the Commission’s *pro forma* open access transmission tariff could support the development of more efficient or cost-effective transmission facilities.⁸⁶ Such reforms included, *inter alia*, the requirement for transmission providers to participate in regional planning processes; the requirement that such regional transmission planning processes must consider transmission needs that are driven by public policy requirements; and the requirement that transmission providers develop a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation, with such method having to satisfy six regional cost allocation principles.

33. But Order No. 1000 was built on what may be a foundation of sand known as “*Chevron* deference.” As the D.C. Circuit explained in *South Carolina*, “[t]he court reviews challenges to the Commission’s interpretation of the FPA under the familiar two-step framework of [*Chevron*].”⁸⁷ The D.C. Circuit further explained that, “[i]f the court determines ‘Congress has directly spoken to the precise question at issue,’ and ‘the intent of Congress is clear, that is the end of the matter.’”⁸⁸ This is often referred to as “*Chevron* step one.”⁸⁹ The court stated, in contrast, that “[i]f . . . ‘the statute is silent or ambiguous with respect to the specific issue,’ then the court must determine ‘whether the agency’s answer is based on a permissible construction of the statute.’”⁹⁰ This is often referred to as “*Chevron* step two.”⁹¹ The D.C. Circuit explained that “*Chevron* step two . . . requires [the court] to uphold an agency’s reasonable interpretation of a statute it administers.”⁹² That is, the court applies *Chevron* deference.⁹³

34. In *South Carolina*, the D.C. Circuit applied *Chevron* deference to the Commission’s interpretation of FPA section 206 in affirming many aspects of Order No.

⁶⁹ The process leading to the adoption of Order No. 1000, the final rule’s direct predecessor but one not nearly as sweeping in its application, was described in paragraphs 22 through 24 of that order. Order No. 1000, 136 FERC ¶ 61,051 at PP 22–24.

⁷⁰ Final Rule, 187 FERC ¶ 61,068 at PP 1291–1292.

⁷¹ *Id.* PP 3, 269, 719–720.

⁷² See NOPR, 179 FERC ¶ 61,028 at PP 9, 245.

⁷³ See *id.* P 302.

⁷⁴ See Order No. 1000, 136 FERC ¶ 61,051 at P 685.

⁷⁵ Final Rule, 187 FERC ¶ 61,068 at P 1469 (“[U]nlike under Order No. 1000, transmission providers *cannot* adopt different Long-Term Regional Transmission Cost [A]llocation Methods for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve Public Policy Requirements.”) (emphasis added); see also *id.* P 1474.

⁷⁶ See, e.g., *id.* PP 1291–1292. A more detailed discussion on how the final rule effectively guts the State Agreement Process is in *infra* Section IV.B.1.b.

⁷⁷ See Final Rule, 187 FERC ¶ 61,068 at P 1323 (citations omitted).

⁷⁸ *Id.* P 1547.

⁷⁹ See NOPR, 179 FERC ¶ 61,028 at P 333; NOPR Concurrence at P 15.

⁸⁰ See NOPR, 179 FERC ¶ 61,028 at PP 400–413.

⁸¹ Final Rule, 187 FERC ¶ 61,068 at P 1625.

⁸² See *id.* PP 86, 253.

⁸³ See *supra* Section I.

⁸⁴ 762 F.3d 41.

⁸⁵ E.g., Final Rule, 187 FERC ¶ 61,068 at PP 86, 253, 256 & n.604, 257 & n.605, 277.

⁸⁶ *Id.* P 16 (citing Order No. 1000, 136 FERC ¶ 61,051 at P 3).

⁸⁷ *South Carolina*, 762 F.3d at 54 (citing *Chevron*, 467 U.S. 837).

⁸⁸ *Id.* (quoting *Chevron*, 467 U.S. at 842).

⁸⁹ See, e.g., *id.* at 84.

⁹⁰ *Id.* at 54 (quoting *Chevron*, 467 U.S. at 843).

⁹¹ See, e.g., *id.* at 58–59 (citing *Chevron*, 467 U.S. at 843), 84.

⁹² *Id.* at 76 (citing *Nat’l Cable & Telecomms. Ass’n v. Brand X Internet Servs.*, 545 U.S. 967, 982 (2005)).

⁹³ Note, however, that the U.S. Supreme Court is revisiting the 40-year-old doctrine and has indicated that it may narrow or overturn it in the pending cases, *Loper Bright Enterprises v. Raimondo*, No. 22–451 (argued Jan. 17, 2024) and *Relentless v. Dep’t of Commerce*, No. 22–1219 (argued Jan. 17, 2024).

1000, including its planning mandates.⁹⁴ In affirming the planning mandates, the court emphasized that Order No. 1000 focused on process and *not* substantive outcomes:

In Order No. 1000, the Commission expressly “decline[d] to impose obligations to build or mandatory processes to obtain commitments to construct transmission facilities in the regional transmission plan.” More generally, the Commission disavowed that it was purporting to “determine what needs to be built, where it needs to be built, and who needs to build it.” As the Commission explained on rehearing, “*Order No. 1000’s transmission planning reforms are concerned with process*” and “*are not intended to dictate substantive outcomes.*” *The substance of a regional transmission plan and any subsequent formation of agreements to construct or operate regional transmission facilities remain within the discretion of the decision-makers in each planning region.*⁹⁵

35. Similarly, in determining that Order No. 1000’s public policy mandate fell within the Commission’s authority under section 206, the D.C. Circuit noted the mandate did not promote any particular public policy:

[Petitioners] seem to argue that the Commission can only exercise authority to promote goals specified in the FPA and that the public policy mandate cannot be justified with respect to any of those goals. This argument misunderstands the nature of the mandate. *It does not promote any particular public policy* or even the public welfare generally. The mandate simply recognizes that state and federal policies might affect the transmission market and directs transmission providers to consider that impact in their planning decisions. . . . This fits comfortably within the Commission’s authority under Section 206. . . . [T]he public policy mandate bears directly on the provision of transmission service.⁹⁶

Just as with Order No. 1000’s planning mandates, the court again emphasized Order No. 1000’s public policy mandate required the establishment of processes:

But petitioners’ attack is once again based on a misunderstanding of the orders. The orders merely require regions to establish *processes* for identifying and evaluating public policies that might affect transmission needs. The regions are free to choose their own manner of determining how best to identify and accommodate these policies.⁹⁷

36. Finally, in affirming Order No. 1000’s requirements pertaining to cost allocation, the court again applied *Chevron* deference to its interpretation of section 206.⁹⁸ The court noted that Order No. 1000 used a “light touch” in its cost allocation reforms:

In keeping with the overall approach of the transmission planning reforms, [Order No. 1000] uses a light touch: it does not dictate

how costs are to be allocated. Rather, [Order No. 1000] provides for general cost allocation principles and leaves the details to transmission providers to determine in the planning processes.⁹⁹

37. While Order No. 1000 used a “light touch,” this pretextual final rule is heavy handed. To ensure that policy and corporate-driven projects are ultimately built so that the preferred generation is built, the final rule seeks to promote particular public policies and to dictate substantive outcomes through its reforms to the Commission’s transmission planning and cost allocation processes.¹⁰⁰ If Order No. 1000 was upheld precisely because it was only mandating *processes*, not *outcomes*, then this final rule cannot stand on *South Carolina* because it nakedly intends to produce very specific outcomes.

38. How does it intend to do this? First, in contrast to Order No. 1000, which mandated consideration of public policies in transmission planning but *not* a particular policy,¹⁰¹ the final rule *requires* transmission providers in their Long-Term Regional Transmission Planning to incorporate seven categories of factors—*i.e.*, specific policies, as I have emphasized. Most of these mandatory categories of factors, which drive long-term transmission planning, specifically relate to the development and purchase of “green energy,” including, *inter alia*: (i) *state and local laws affecting the resource mix*, (ii) *state and local laws on decarbonization*, (iii) *generator interconnection requests and withdrawals*,¹⁰² and (iv) *corporate, state and local government commitments to purchase “green energy.”*

39. The final rule describes the relationship between the categories of factors, transmission needs, and benefits, among other terms:

For purposes of this final rule, Long-Term Regional Transmission Planning means regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis to identify Long-Term Transmission Needs, identify transmission facilities that meet such needs, measure the benefits of those transmission facilities, and evaluate those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation as the more efficient or cost-effective regional transmission facilities to meet Long-Term Transmission Needs.

For purposes of this final rule, Long-Term Transmission Needs are transmission needs identified through Long-Term Regional Transmission Planning, which, as discussed in this final rule, includes running scenarios and *considering the enumerated categories of factors*.¹⁰³

Thus, categories of factors clearly shape the identification of transmission needs.

⁹⁹ *Id.* at 81.

¹⁰⁰ In so doing, the final rule violates section 201 as well. *See infra* Section III.B.

¹⁰¹ *See South Carolina*, 762 F.3d at 89–90.

¹⁰² This factor category is another way to subsidize and prefer wind and solar developers, which dominate the interconnection queues.

¹⁰³ Final Rule, 187 FERC ¶ 61,068 at PP 38–39 (emphasis added).

Demonstrating this causal relationship, the final rule explains that “best available data inputs are data inputs that . . . reflect the *list of factors* that transmission providers account for in their Long-Term Scenarios,”¹⁰⁴ and, in turn, “Long-Term Scenarios . . . incorporate various assumptions using best available data inputs about the future electric power system . . . to identify Long-Term Transmission Needs and enable the identification and evaluation of transmission facilities to meet such transmission needs.”¹⁰⁵

40. And, as we know, the identification of needs leads to the identification of transmission facilities that meet such needs; the identification of transmission facilities in turn leads to the measure of the benefits associated with those facilities; and the measure of benefits informs the evaluation of those transmission facilities for potential selection in the regional transmission plan for purposes of cost allocation. Thus, as the categories of factors are slanted toward transmission to facilitate preferred generation, the resulting output of the transmission planning process will inevitably have a similar bent. In other words, the final rule’s mandate of the categories of factors starts the domino effect toward the final rule’s agenda, an agenda that goes far beyond Order No. 1000.

41. Second, in contrast to Order No. 1000, whose reforms “[were] concerned with process” and “[were] not intended to dictate substantive outcomes,”¹⁰⁶ the final rule requires transmission providers to measure a set of seven required benefits in their long-term transmission planning so that the pretextual agenda will be realized. By mandating minimum benefits that the transmission providers must use to evaluate potential transmission facilities,¹⁰⁷ the final rule is doing the opposite of using a “light touch;” rather, the final rule is putting its thumb on the scale, seeking to dictate outcomes of the transmission planning process. As I must continue to emphasize, by mandating benefits, the final rule makes consumers into involuntary “beneficiaries,” who, through regional cost allocation, will be forced to pay for transmission projects that support the development and purchase of preferential power. Accordingly, as with the final rule’s mandated categories of factors, the mandatory minimum benefits serve to advance the final rule’s specific policy objectives regarding the resource mix. Such favoritism is blatantly unduly discriminatory and preferential in contravention of section 206, and therefore, the final rule is, simply put, not entitled to *Chevron* deference in any form.

B. The Final Rule Violates FPA Section 201

42. The final rule also infringes on the states’ authority over electric generation reserved to them by FPA section 201 and is thus *ultra vires*.

43. As relevant here, FPA section 201(b) provides:

¹⁰⁴ *Id.* PP 42, 633 (emphasis added).

¹⁰⁵ *Id.* PP 40 and 302 (emphasis added).

¹⁰⁶ *See South Carolina*, 762 F.3d at 58 (internal citation omitted).

¹⁰⁷ Final Rule, 187 FERC ¶ 61,068 at P 965.

⁹⁴ *See South Carolina*, 762 F.3d at 56–59 (internal citations omitted).

⁹⁵ *Id.* at 57–58 (emphasis added; internal citations omitted).

⁹⁶ *Id.* at 89–90 (citation omitted).

⁹⁷ *Id.* at 91 (emphasis in original; internal citations omitted).

⁹⁸ *Id.* at 84–86.

The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.*¹⁰⁸

Further, section 201(a) also specifies that “such Federal regulation . . . extend[s] only to those matters which are not subject to regulation by the States.” Courts have found that “states have broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction. States may, for example, order utilities to build renewable generators themselves, or . . . order utilities to purchase renewable generation.”¹⁰⁹ These powers are reserved to the states under section 201.

44. In *South Carolina*, the D.C. Circuit rejected the argument that section 201 prohibited Order No. 1000’s transmission planning mandate.¹¹⁰ The D.C. Circuit emphasized that “because the planning mandate relates wholly to electricity transmission, *as opposed to electricity sales*, it involves a subject matter over which the Commission has relatively broader authority.”¹¹¹ The court also reasoned that “because [Order No. 1000’s] planning mandate is directed at ensuring the proper functioning of the interconnected grid spanning state lines, . . . the mandate fits comfortably within Section 201(b)’s grant of jurisdiction over ‘the transmission of electric energy in interstate commerce.’”¹¹² The court thus concluded that “Section 201 [did] not preclude the Commission’s regulation of transmission planning in [Order No. 1000]” and that Order No. 1000 “[did] not interfere with the traditional state authority that is preserved by Section 201.”¹¹³

45. However, in contrast to Order No. 1000, the final rule absolutely does “interfere with the traditional state authority that is preserved by Section 201” to ensure that its preferential policy and corporate-driven projects get built. By mandating, *inter alia*, categories of factors that drive the transmission planning process and by mandating minimum benefits to be used in the evaluation of potential Long-Term Regional Transmission Facilities, the final rule seeks to spur the building of transmission so as to promote a specific policy objective: the development and purchase of preferential generation. Accordingly, although the final rule strenuously insists that it is not mandating *outcomes*,¹¹⁴ it is doing so by manipulating

the *inputs* of transmission planning (*i.e.*, “pre-cooking”).¹¹⁵ In other words, the final rule seeks to do indirectly what it may not do directly.

46. As I explained in my concurrence to the NOPR:

States can prefer, mandate or subsidize specific types of generation resources, but the Commission cannot use its authority over transmission to pressure, steer or require regional planning entities to act as the Commission’s agents and do indirectly what the Commission cannot do directly. The Commission is not a national integrated resource planner. Order No. 1000, to its credit, recognized this clear delineation between federal and state authority.¹¹⁶

I also explained that “the Commission cannot *impose* a preference for certain types of generation *nor require* regional entities to plan transmission designed to prefer or facilitate one type of generation over another.”¹¹⁷

47. The text of the FPA gives this Commission *no* authority whatsoever to act as a national IRP planner for the purpose of promoting its preferred generation resource mix. Pulling back the curtain, that is exactly what this pretextual final rule seeks to do. By extending FERC’s control over every public utility transmission planner in the country, RTO or non-RTO, and ordering them to plan transmission lines intended to advance preferred policy and corporate goals, the Commission is stepping into the role of national IRP planner. FERC’s authority under the FPA is limited to matters that *directly* affect rates, not practices that may theoretically have some tangential, indirect effect on rates,¹¹⁸ especially improper purposes such as ordering transmission planning to promote one or more states’ public policies or corporate goals as to preferred generation resources. Congress intended FERC to be a rate regulator, not a planner of generation or transmission designed to bring about the construction of preferred types of generation. Indeed, FPA section 215 explicitly states that FERC may *not* order the construction of any generation or transmission asset.¹¹⁹ FERC cannot order

transmission providers to do what FERC itself has no authority to do, yet that is exactly what this final rule aims to do.

48. The final rule purports to order transmission planners to plan for a “predicted” generation mix in a distant future 20 years away, but the exact generation mix in 20 years is impossible to predict.¹²⁰ The real goal of this pretextual final rule is not to try the impossible by predicting the generation mix in 20 years. Instead, the final rule is an attempt to become a national IRP planner and *bring about* a preferred generation mix through transmission planning by manipulating and shaping the future generation mix the special interests supporting this final rule want now.

49. The final rule denies that it is infringing on state authority reserved under FPA section 201, arguing, *inter alia*, that it directly regulates only those practices that affect the rates for the transmission of electric energy in interstate commerce and that it is not aiming to indirectly regulate any matter reserved to the states by FPA section 201.¹²¹

FERC has no authority to order a load-serving public utility to build a specific generation facility, only states can. See 16 U.S.C. 824(b)(1); *see also Hughes v. Talen Energy Mktg.*, 578 U.S. 150, 154 (2016) (“The States’ reserved authority includes control over in-state ‘facilities used for the generation of electric energy.’” (quoting 16 U.S.C. 824(b)(1))); *see also* 16 U.S.C. 824o(i)(2) (“[Section 215 of the FPA] does not authorize the [Electric Reliability Organization, *i.e.*, NERC] or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or service.”). Congress recently gave FERC a narrowly limited form of “backstop” siting authority for certain designated transmission lines, but that authority is not implicated in this final rule.

¹²⁰ PATH Concurrence at P 4 (“PATH graphically illustrates the inherent dangers in approving for regional cost allocation long-distance projects based on a prediction (*i.e.*, a guess) of what the generation mix will be in 20 years or more. PATH was originally part of the huge “Project Mountaineer” scheme—announced with great fanfare right here at the Commission itself—to build *three* high-voltage lines across hundreds of miles from West Virginia to East Coast load centers. The vast majority of the power to be delivered along these lines was to be coal-generated. After running into a firestorm of opposition in both the states in the path (no pun intended), as well as the end-user load states, Project Mountaineer was abandoned except for the PATH project, which represented a segment of one of the proposed Project Mountaineer lines. That segment was never built either. Yet, consumers have been paying for it ever since. The lesson here is clear: For policy-driven long-distance, regional transmission projects affecting consumers in multiple states, it is absolutely essential that state regulators have the authority to approve—or disapprove—the construction of these lines and how they are selected for regional cost allocation and what that cost allocation formula is, if their consumers are going to be hit with the costs.”) (emphasis in original).

¹²¹ Final Rule, 187 FERC ¶ 61,068 at P 263; *see also, e.g., id.* P 271 (“[T]he requirements in this final rule respect and do not unlawfully infringe on state authority. Rather . . . the Commission is acting in an area squarely within its jurisdiction—transmission planning and cost allocation—by requiring transmission providers to engage in Long-Term Regional Transmission Planning to remedy deficiencies in the current transmission planning and cost allocation processes.”).

¹¹⁵ *Id.* P 965.

¹¹⁶ NOPR Concurrence at P 2; *see also id.* n.4 (quoting Order No. 1000, 136 FERC ¶ 61,051 at P 154 (“[T]he regional transmission planning process is not the vehicle by which integrated resource planning is conducted; that may be a separate obligation imposed on many public utility transmission providers and under the purview of the states.”) (emphases added in NOPR Concurrence)).

¹¹⁷ *Id.* P 12 (emphases in original).

¹¹⁸ *See, e.g., CAISO v. FERC*, 372 F.3d at 400 (holding that FERC cannot prescribe the membership of the CAISO board, as FERC has authority over only “rates, charges, classifications, and closely related matters”); *see also Ari Peskoe, Replacing the Utility Transmission Syndicate’s Control*, Energy Law Journal, Vol. 44.3 547, 578 (2023) (Peskoe Article) (“FERC’s authority over utility ‘practices’ is best understood as referring to ‘actions habitually being taken by a utility in connection with a rate found to be unjust and unreasonable.’”) (footnote omitted), <https://www.eba-net.org/wp-content/uploads/2023/11/8-Peskoe547-618.pdf>.

¹¹⁹ FERC regulates RTOs and RTO markets to ensure just and reasonable rates to consumers, but

¹⁰⁸ 16 U.S.C. 824(b)(1) (emphases added).

¹⁰⁹ *See, e.g., Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d at 417 (quoting *S. Cal. Edison Co. San Diego Gas & Elec. Co.*, 71 FERC at 62,080).

¹¹⁰ 762 F.3d at 62–64.

¹¹¹ *Id.* at 63 (emphasis added) (footnote omitted).

¹¹² *Id.* (internal citations omitted).

¹¹³ *Id.* at 64.

¹¹⁴ *See* Final Rule, 187 FERC ¶ 61,068 at PP 954–955, 1026–1028.

The final rule is chock-full of “nothing to see here” rhetoric asserting that it does not seek to shape the generation resource mix, but merely responds to changes in the electric industry.¹²² “Pay no attention to the [agenda] behind the [green] curtain!”¹²³ the final rule insists across 1300 pages. But it should be obvious by now that the final rule is just a pretext for enacting this administration’s “net zero 2035” policy agenda, as well those of corporate and other special interests.¹²⁴ The true intent of the final rule is revealed by mandated categories of factors and minimum benefits, which drive the transmission development necessary to achieve the final rule’s preferred generation resource mix. Any honest account of the final rule cannot ignore the monetary windfall it would shower on generation and transmission developers; it is no wonder, therefore, why they were among the strongest supporters for the final rule. Nor can any rational individual—unless living in the Land of Oz—reasonably deny the role the final rule plays in furthering this pretextual agenda.¹²⁵ In light of this backdrop, the final rule’s repeated assertions that it does not seek to shape the country’s resource mix are simply not credible. Contrary to the final rule’s claims, in violation of FPA section 201, the final rule transforms the Commission into a national IRP planner to promote the construction of transmission lines to further the development of the final rule’s preferred generation resources.

C. The Final Rule Violates the Major Questions Doctrine

50. Courts generally look with suspicion on “cryptic” delegations of authority,¹²⁶ and they are generally skeptical of agencies that seek to find “elephants in mouseholes,” or otherwise seek to rely on tiny grants of authority to justify major actions.¹²⁷ As the Supreme Court explained in *West Virginia v. EPA*:

Where the statute at issue is one that confers authority upon an administrative agency, that inquiry must be “shaped, at least in some measure, by the nature of the question presented”—whether Congress in fact meant to confer the power the agency has asserted. In the ordinary case, that context has no great effect on the appropriate analysis. Nonetheless, our precedent teaches that there are “extraordinary cases” that call for a different approach—cases in which the “history and the breadth of the authority that [the agency] has asserted,” and the “economic and political significance” of that assertion, provide a “reason to hesitate before concluding that Congress” meant to confer such authority.¹²⁸

¹²² E.g., *id.* PP 129, 130, 254, 259–263, 266, 271, 275.

¹²³ You can decide for yourself whether the “green curtain” represents “green energy” or something else that’s green.

¹²⁴ See *supra* Sections I, III.B.

¹²⁵ See *supra* nn.5, 8, 10, 13, 15, 16, 67.

¹²⁶ See *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 160 (2000).

¹²⁷ See *West Virginia v. EPA*, 597 U.S. at 746–47 (Gorsuch, J., concurring) (quoting *Whitman v. Am. Trucking Ass’n*, 531 U.S. 457, 468 (2001)).

¹²⁸ *Id.* at 700 (internal citations omitted).

51. I invoked the major questions doctrine in my dissent to the proposed changes to the Commission’s certificate policy, even before *West Virginia v. EPA* was handed down. In my dissent, I wrote that:

“The federal government’s powers . . . are not general[] but limited and divided. Not only must the federal government properly invoke a constitutionally enumerated source of authority to regulate in this area or any other, it must also act consistently with the Constitution’s separation of powers. And when it comes to that obligation, this Court has established at least one firm rule: ‘We expect Congress to speak clearly’ if it wishes to assign to an executive agency decisions ‘of vast economic and political significance.’ We sometimes call this the major questions doctrine.”

In short, the major questions doctrine presumes that Congress reserves major issues to itself, so unless a grant of authority to address a major issue is explicit in a statute administered by an agency, it cannot be inferred to have been granted.

* * * * *

Yet the Supreme Court has made it clear that broad deference to administrative agencies on major questions of public policy is not in order when statutes are lacking in any explicit statutory grant of authority. “When much is sought from a statute, much must be shown. . . . [B]road assertions of administrative power demand *unmistakable legislative support*.”¹²⁹

52. The final rule’s actions clearly implicate the major questions doctrine. If imposing a final rule intended to cost consumers literally trillions of dollars to build transmission projects designed to implement a sweeping policy agenda never passed by Congress is *not* a major question of public policy, then there is no such thing.¹³⁰

53. Yet the final rule brushes aside arguments that it would not withstand scrutiny under the major questions doctrine.¹³¹ Against these arguments, the final rule denies that its aim is to influence the generation mix;¹³² asserts that it “neither transforms nor expands the Commission’s authority; it merely applies existing authority;”¹³³ asserts that “the differences in transmission planning required by this final

¹²⁹ *Certification of New Interstate Nat. Gas Facilities*, 178 FERC ¶ 61,107 (2022) (Christie, Comm’r, dissenting at P 22–23 (quoting *Nat’l Fed’n of Indep. Bus. v. Dep’t of Labor, OSHA*, 595 U.S. 109, 121–22 (2022) (Gorsuch, J., concurring); *In re MCP No. 165*, 20 F.4th 264, 267–68 (6th Cir. 2021) (Sutton, C.J., dissenting (emphases added))) (internal citations omitted) (Certificate Dissent), <https://www.ferc.gov/news-events/news/items-c-1-and-c-2-commissioner-christies-dissent-certificate-policy-and-interim>.

¹³⁰ See Brad Plumer, *Energy Dept. Aims to Speed Up Permits for Power Lines*, *The New York Times*, Apr. 25, 2024 (quoting Rob Gramlich, the president of the consulting group Grid Strategies, “‘I’ve called [the final] rule the biggest energy policy in the country.’” (emphasis added)), <https://www.nytimes.com/2024/04/25/climate/energy-dept-speed-transmission.html>.

¹³¹ Final Rule, 187 FERC ¶ 61,068 at P 275.

¹³² *Id.*

¹³³ *Id.* P 277.

rule represent differences in degree, not kind, from the Commission’s longstanding regulations;”¹³⁴ and asserts that its “incremental process improvements [from Order No. 1000], while necessary to ensure just and reasonable Commission-jurisdictional rates, do not have the ‘vast economic and political significance’ that would implicate the major questions doctrine.”¹³⁵ None of these assertions are credible.

54. This final rule violates the major questions doctrine. As discussed above, it is axiomatic that Congress has not intended for the Commission to be a national IRP planner. On the contrary, it has left both the siting of transmission and the development of generation to the states.¹³⁶ Yet the final rule encroaches on these traditional state prerogatives in the absence of any explicit Congressional authorization to do so.

55. The final rule seeks to shape specific policy outcomes by mandating categories of factors and minimum benefits. In addition, the final rule does something else that also arguably makes it transformative. Citing, *inter alia*, *South Carolina*, the final rule declares that the Commission has exclusive jurisdiction over regional transmission planning and cost allocation processes:

As the D.C. Circuit has recognized, regional transmission planning and cost allocation processes are practices affecting rates subject to the Commission’s *exclusive* jurisdiction.¹³⁷

In fact, the *South Carolina* court did *not* state that the Commission has *exclusive* jurisdiction over regional transmission planning and cost allocation. In fact, that court noted, for example, that the Florida Public Service Commission is statutorily vested with authority to “plan[], develop[], and main[tain] . . . a coordinated electric power grid” throughout the state.¹³⁸

56. Whether the Commission can exclusively supplant the states in transmission planning and cost allocation is a major question—particularly considering the enormous breadth of the transmission

¹³⁴ *Id.*

¹³⁵ *Id.* P 278 (quoting *West Virginia v. EPA*, 597 U.S. at 735 (J. Gorsuch, concurring)).

¹³⁶ See *supra* Section III.B. Since 2005, FERC has had very limited backstop siting authority for certain transmission projects that has never been used. See generally *Applications for Permits to Site Interstate Elec. Transmission Facilities*, Order No. 1977, 187 FERC ¶ 61,069 (2024).

¹³⁷ Final Rule, 187 FERC ¶ 61,068 at P 86 & n.184 (emphasis added) (citing *South Carolina*, 762 F.3d at 55–59, 84 (affirming the Commission’s authority to regulate transmission planning and cost allocation as practices affecting rates); Order No. 1000–A, 139 FERC ¶ 61,132 at P 577 (holding that “requirements regarding transmission planning and cost allocation . . . are practices affecting rates.”)); see also *id.* P 130 (“Instead, because practices directly affecting Commission-jurisdictional rates, terms, and conditions of service for interstate transmission and wholesale electricity are the *exclusive jurisdiction of the Commission*, we must ensure that Commission-jurisdictional processes associated with regional transmission planning and cost allocation result in rates that are just and reasonable and not unduly discriminatory or preferential.”) (emphasis added); *id.* P 770.

¹³⁸ See, e.g., *South Carolina*, 762 F.3d at 62 n.3.

grid, the importance of electricity in everyday life, and the trillions of dollars in transmission investment (read, cost increases) this final rule intends to impose on consumers.¹³⁹ The final rule's conclusion that regional transmission planning and cost allocation processes are subject to the Commission's exclusive jurisdiction suggests that the Commission "occupies the field"¹⁴⁰ in these areas.¹⁴¹ But this is wrong. This pretextual final rule erodes the states' authority, which is inconsistent with the principle of cooperative federalism reflected in the FPA. Under the major questions doctrine, absent an act of Congress, the Commission may not usurp the powers of the states in this manner.

IV. The Final Rule Fails Under Both Prongs of FPA Section 206

57. I cannot support the final rule because it has been fundamentally changed from the NOPR. In jettisoning essential components of the NOPR, the final rule has been reduced to a mere pretext for this supposedly independent Commission's effort to implement the current administration's "net zero 2035" policies. It will not produce rates that are just and reasonable and not unduly discriminatory or preferential. This final rule does not satisfy either of the requirements of FPA section 206. Under section 206, the Commission must first find that the rate on file is no longer just and reasonable and not unduly discriminatory or preferential. Then the Commission must find that a particular replacement rate would be just and reasonable and not unduly discriminatory or preferential.¹⁴² The final rule fails on both counts.

58. Although the current regional transmission planning processes could be improved—they are certainly not in need of the final rule's *solutions*. Even if these solutions were the only way forward to reform regional transmission planning, an act of Congress would be necessary first because the final rule is far beyond the reach of the FPA. While the Commission might *prefer* a different rate, that preference alone does not make all the filed rates of every transmission provider unjust and unreasonable.

¹³⁹ See *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016) ("It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level.").

¹⁴⁰ See *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238, 248 (1984) ("If Congress evidences an intent to occupy a given field, any state law falling within that field is preempted." (citation omitted)); *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467, 475–476 (4th Cir. 2014) ("Even where state regulation operates within its own field, it may not intrude indirectly on areas of exclusive federal authority." (quoting *Pub. Utils. Comm'n of State of Cal. v. FERC*, 900 F.2d 269, 274 n.2 (D.C. Cir.1990) (internal quotation marks omitted))).

¹⁴¹ The final rule's determination here aligns with the final rule's complete gutting of the roles of the states in transmission planning and cost allocation. See *infra* Section IV.B.1.

¹⁴² 16 U.S.C. 824e.

A. The Final Rule Fails To Justify Its Action Under Section 206

59. The final rule presents no justification for taking action in *this proceeding* against *all* of the filed transmission rates pursuant to FPA section 206. The record, while consisting of thousands of pages of comments, simply does not contain substantial evidence sufficient to make a generic showing that the existing filed rates of all transmission providers are unjust, unreasonable, unduly discriminatory or preferential.¹⁴³ In *South Carolina*, the D.C. Circuit explained that "the substantial evidence test" for a rulemaking proceeding "'requires the Commission to specify the evidence on which it relied and to explain how that evidence supports the conclusion it reached.'" ¹⁴⁴ Here, the final rule's "rel[iance] on 'generic' or 'general' findings of a systemic problem to support imposition of an industry-wide solution" ¹⁴⁵ fails because it relies on cherry-picked special interest comments to support the pre-baked and pretextual findings needed to enact the administration's preferential, and *discriminatory*, policy agenda as well those of corporate and other special interests.

1. The Record Is Not Sufficient to Make a Generic Showing That Every Transmission Providers' Regional Transmission Planning and Cost Allocation Processes Are Unjust, Unreasonable, and Unduly Discriminatory or Preferential

60. The evidence in the record that is used to support the final rule's section 206 finding consists largely of comments from special interests that will profit from the final rule. The final rule also signals that there has been limited regional transmission development since Order No. 1000. This evidence should not be used to mean that every transmission provider in the country has transmission practices that are unjust and unreasonable.

61. The final rule declines to analyze the "justness and reasonableness of either generator interconnection processes or local transmission planning processes" in its survey of issues in regional transmission planning.¹⁴⁶ The final rule identifies benefits of transmission planning.¹⁴⁷ The final rule states that "transmission planning that considers both evolving reliability needs and other drivers of transmission needs more comprehensively can enable transmission providers to identify potential reliability problems and economic constraints."¹⁴⁸ The final rule states that transmission spending has increased, which turns into higher customer bills.¹⁴⁹ The final rule identifies projections are necessary for growing future transmission needs, including load growth¹⁵⁰ and changing reliability needs.¹⁵¹

¹⁴³ See *South Carolina*, 762 F.3d at 64–65 (citations omitted).

¹⁴⁴ *Id.* at 54 (quoting *Wis. Gas Co. v. FERC*, 770 F.2d 1114, 1156) (alterations in the original)).

¹⁴⁵ See Final Rule, 187 FERC ¶ 61,068 at P 132 (citing *South Carolina*, 762 F.3d at 67) (additional citation omitted).

¹⁴⁶ *Id.* P 111.

¹⁴⁷ *Id.* PP 90–91.

¹⁴⁸ *Id.* P 90.

¹⁴⁹ *Id.* P 92.

¹⁵⁰ *Id.* P 95.

¹⁵¹ *Id.* PP 93–94.

And supply is changing due to state policies, customer preferences, and utility preferences (the latter two can also be driven by state policies or by activist investor preferences).¹⁵²

62. Translating FERC-speak, we are left with bland statements of the obvious: Transmission is expensive to build; transmission spending is up; generators front a lot of the needed money; consumers eventually pay them back; lack of regional integrated planning results in piecemeal transmission construction; this is inefficient and costs consumers more. Yet simply because a rate could be more efficient, that alone is not enough to make the filed rate unjust and unreasonable.

63. Many of the special interest commenters point to studies, projections, and reports that show that regional transmission planning could be done more efficiently.¹⁵³ When we peel back the "green curtain" shrouding this final rule, however, we see that these comments are almost exclusively from self-interested entities which would gain substantially from the very Commission action that they support.¹⁵⁴ Indeed, the record being used to support the section 206 finding consists of special interests who are going to profit monetarily from the final rule, including generation developers, transmission developers, and corporate purchasers of preferred power.¹⁵⁵ None of these comments (individually or taken together) are sufficient to meet the high burden of proof that all transmission providers' tariffs are unjust and unreasonable due to the profit-seeking motivations behind them.

64. In addition, the final rule looks back over the period following Order No. 1000 and states that regional transmission planning processes have yielded only "limited investments in regional transmission planning projects."¹⁵⁶ Let's suppose that over the last decade a transmission developer had instead proposed massively expanding transmission while the load growth projections remained flat. Consumers commenting on that aggressive plan would have challenged it as gold-plating. Regulators

¹⁵² *Id.* PP 96–97.

¹⁵³ See, e.g., Johannes Pfeifenberger, et al., *The Brattle Group and Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, at 48–49 (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf; Rob Gramlich and Jay Caspary, *Americans for a Clean Energy Grid, Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at 26–28 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf; Johannes P. Pfeifenberger, et al., *The Brattle Group, Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* (Apr. 2019), https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf.

¹⁵⁴ Such commenters include ACORE, PIOs, ACEG, Advanced Energy Buyers, AEE, Renewable Northwest, SREA, and Clean Energy Buyers.

¹⁵⁵ See Final Rule, 187 FERC ¶ 61,068 at P 96.

¹⁵⁶ *Id.* P 101.

would have rejected it as imprudent. The so-called “limited investments” were instead a sign of responsiveness to projections made during that era. Rather than seeing this outcome as a feature of considered ratemaking during a period of low load growth, the final rule attributes this lack of investment to the shortcomings of the existing regional transmission planning processes—meaning the tariff changes mandated by Order No. 1000.¹⁵⁷ For these reasons, the final rule’s reliance on a lack of regional transmission development post-Order No. 1000 is not persuasive, especially to support the finding that all transmission providers’ tariffs are unjust and unreasonable.

2. The Record Shows That Regional Planning Deficiencies Exist *Only* in Isolated Pockets

65. The evidence in this record does not demonstrate a single nationwide systemic problem. Rather, the record shows that the “deficiencies identified by the Commission ‘exist[] only in isolated pockets.’”¹⁵⁸ The final rule even recognizes the many regions representing a substantial percentage of consumers where regional transmission planning is working.¹⁵⁹ The final rule points to the MISO Multi-Value Project transmission planning process as an effective example of regional transmission planning.¹⁶⁰ From this, it could be concluded that the final rule suggests that regional transmission planning is working in MISO, including on a long-term basis. It is logical to conclude similarly regarding CAISO’s¹⁶¹ and New York’s regional transmission planning.¹⁶² Vertically integrated monopoly public utilities have expanded their transmission capacity by engaging in integrated resource planning that is reviewed and approved by their state regulators.¹⁶³ NRECA, an organization representing both transmission providers and transmission-dependent entities, highlights that its members have observed regional transmission planning processes that range

from successful to broken.¹⁶⁴ According to NRECA, some RTO regions are working, and others are not. NRECA similarly states that some non-RTO regions are working, and others are not.

66. This is hardly ironclad evidence sufficient to support a generic finding that the regional transmission planning processes are no longer just and reasonable. The record here shows that regional and multistate regional planning is happening in significant and large swaths of the country subject to our rate jurisdiction, including on longer-term horizons, and that other regions have room for improvement. These circumstances are entirely different than those facing the Commission when it issued Order No. 1000. The factual justification for a single, national FPA section 206 finding is simply not present in the way it was for Order No. 1000. No amount of hand waving or misdirection can change the lack of sufficient evidentiary support for this Commission to take the sweeping national action pursuant to FPA section 206 in this rule. This significant deficiency leaves this *entire* exercise open to meaningful challenge.

B. The Replacement Rate Is Not Just and Reasonable

67. Not only does the final rule fail to meet its evidentiary burden, but the replacement rate that the final rule imposes is not just and reasonable and has no basis in law. The final rule has removed any serious state role in agreeing to the final rule’s planning and cost allocation processes, and the final rule fails to protect consumers as FERC is required to do under the FPA. Further, the cost causation principle cannot, and should not, extend as far as the today’s final rule suggests, and should not require that the ratepayers of a non-consenting state pay costs of other states’ public policies where there is mismatch between planning criteria and benefits.

1. The Final Rule Reverses the States’ Roles in Transmission Planning and Cost Allocation Promised by the NOPR

68. The main reason I supported the NOPR was that it “*formally* put the states—for the first time—at the center of regional transmission planning and cost allocation decision-making for policy-driven projects in *all* regional transmission entities, if the states choose.”¹⁶⁵ Specifically, I explained:

[F]or these [Long-Term Regional Transmission Facilities] the NOPR propose[d] to require the regional planning entities to consult with *and seek the agreement* of the relevant states to *both* the selection criteria for these projects *and* to the regional cost allocation arrangements. State approval is especially important in a multi-state region, where different states have different policies. The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements. States can agree to an *ex ante* formula for

regional cost allocation of these types of projects—such as, for example, the “highway-byway” formula approved by the SPP Regional State Committee—or states can agree to a process for a project-by-project agreement on cost allocation among one or several states—such as, for example, the State Agreement Approach in PJM—or states may choose some combination of both. States in a multi-state RTO or ISO can even agree to defer the decision on cost allocation to the governing board of the RTO/ISO. The result is, while we are proposing to require regional planning entities to study and evaluate a broad, forward-looking array of information—including information addressing states’ individual energy policies and goals—any projects identified through this new process will not be built, or more importantly, paid for by consumers, until the states representing such consumers have agreed that such projects are indeed needed and wanted by those same consumers.¹⁶⁶

I wrote about the advantages of elevating the role of the states:

[E]levating the role in planning and cost allocation of state regulators—who are, as a group, deeply concerned about the monthly bills paid by consumers, of which transmission is a rapidly growing component—will make it more likely, not less, that necessary transmission can get built while ensuring that rates resulting from these types of policy-driven projects will not be unjust and unreasonable, which they clearly have the potential to be.¹⁶⁷

The day the Commission issued the NOPR, some of my colleagues expressed similar sentiments.¹⁶⁸

69. Unfortunately—perhaps emanating from the final rule’s erroneous legal conclusion that the Commission has exclusive jurisdiction over regional transmission planning and cost allocation¹⁶⁹—the final rule completely eviscerates the states’ role contemplated in the NOPR in both the transmission planning and cost allocation processes. Other than a few cosmetic gestures, the final rule essentially treats the state regulators like other stakeholders in the RTO/ISO. But states are not mere “stakeholders.”

State regulators have the duty to act in the *public interest* and states alone are sovereign authorities with inherent police powers to regulate utilities through their designated state officers. The FPA itself explicitly recognizes state authority. So it is perfectly fitting for state regulators to have the important roles proposed in this NOPR,

¹⁶⁶ *Id.* P 11 (emphases in original) (footnotes omitted).

¹⁶⁷ *Id.* P 14 (emphasis in original).

¹⁶⁸ See *supra* n.48; NOPR, 179 FERC ¶ 61,028 (Phillips, Comm’r, concurring at P 4) (“I support the proposal to require transmission providers to consult with and incorporate states’ views in project selection and cost allocation. I invite comment on the value of such state involvement for increasing the likelihood that those facilities are sited and ultimately developed with fewer costly delays.”), <https://www.ferc.gov/news-events/news/item-e-1-commissioner-phillips-concurrence-building-future-through-electric>.

¹⁶⁹ See *supra* Section III.C.

¹⁵⁷ *Id.*

¹⁵⁸ See *South Carolina*, 762 F.3d at 67 (quoting *Associated Gas Distribs. v. FERC*, 824 F.2d 981, 1019 (D.C. Cir. 1987)) (alteration in the original).

¹⁵⁹ See *generally* Final Rule, 187 FERC ¶ 61,068 at PP 71–77.

¹⁶⁰ *Id.* P 102; see OMS Initial Comments at 2 (stating that “it is critically important to note at the outset that MISO’s regional planning process already reflects many of the elements and features contained in the [NOPR], and it should be looked to as a model for other regions to emulate.”); MISO Initial Comments at 1–2.

¹⁶¹ CAISO Initial Comments at 3 (“The CAISO already engages in long-term planning, and its existing transmission planning process is consistent with the direction of the NOPR.”); CAISO Reply Comments at 1–2 (stating that “the Commission should not unduly disrupt or undo existing planning processes and approaches that are functioning well and enabling transmission providers to plan for system needs efficiently and cost-effectively.”).

¹⁶² New York Commission and NYSEDA Initial Comments at 5.

¹⁶³ See, e.g., Southern Companies Initial Comments at 13–15 (stating that its “IRP/RFP-driven transmission planning is successfully expanding their electric grid to address the changing resource mix and load”); Undersigned States Reply Comments at 6–7.

¹⁶⁴ NRECA Initial Comments at 14–16.

¹⁶⁵ NOPR Concurrence at P 5 (emphases in original) (footnote omitted).

without preempting the regional planning entities from seeking additional input through their existing stakeholder processes.¹⁷⁰

The evisceration of the states' role in transmission planning and cost allocation and the relegation of state regulators to mere "stakeholder" status is alone reason enough for me to dissent.

a. The Final Rule Undercuts the States' Role in the Transmission Planning Process

70. A major example of the final rule's undercutting of the states' role in the transmission planning process is with respect to the selection criteria. As a reminder, the selection criteria are a key component of the planning process because once a project is selected, money starts to flow from the ratepayers to transmission developers. Recognizing the states' important role in the planning process, the NOPR required that the states *approve* the selection criteria that transmission providers use in the planning process:

Given the important role states play and the wide variety of potential approaches to selection criteria, we propose, as part of this requirement, that public utility transmission providers must consult with and seek support from the relevant state entities, as defined below, within their transmission planning region's footprint to develop the selection criteria.¹⁷¹

To implement this requirement, the NOPR proposed "to require that public utility transmission providers demonstrate on compliance that they developed their proposed selection criteria in consultation with the relevant state entities in their transmission planning region's footprint." ¹⁷² And it was clear at that time exactly what that meant—*agreement, nothing less.*¹⁷³ However, the final rule outright undermines these requirements—and the states' role as a whole—by "clarifying" that state approval of the evaluation process and selection criteria is *not actually required*:

We clarify that we require transmission providers to *seek support* from Relevant State Entities, but *do not require transmission providers to obtain their support*, before proposing an evaluation process and selection criteria on compliance.¹⁷⁴

Starkly demonstrating how milquetoast the requirement for transmission providers to "consult with and seek support from" the states has now become under the final rule, the final rule even fails to require that

transmission providers indicate in their compliance filings whether the states agree with their selection criteria proposal.¹⁷⁵ So, from the NOPR requiring state agreement, the final rule does not even require the states' views to merit mere mention. Adding insult to injury, the final rule specifies that "transmission providers *may not* include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities."¹⁷⁶

71. The final rule acknowledges that "Long-Term Regional Transmission Planning is more likely to be successful where transmission providers, Relevant State Entities, and other stakeholders collaborate to develop an evaluation process and selection criteria."¹⁷⁷ But the final rule emphasizes that transmission providers are ultimately the only ones responsible for transmission planning and complying with the obligations of the final rule, and it notes that achieving consensus may simply not be possible in every instance.¹⁷⁸ Neither explanation provides a sufficient rationale to justify undercutting the requirement for state approval when states alone have the inherent police power to regulate the utilities within their states. One cannot help but see this as part of the larger pretextual shell game the final rule seeks to accomplish. Sadly, this is one of many examples where the final rule provides for a little extra process involving the states to demonstrate ostensibly that the Commission is committed to the principle of cooperative federalism, but in substance, states are relegated back to mere stakeholders, whose input can simply be disregarded if inconvenient.¹⁷⁹

72. Unfortunately, not only the states' role with respect to the selection criteria has been gutted. As I must continue emphasize,¹⁸⁰ by mandating categories of factors and minimum benefits, the final rule seeks to shape specific policies and outcomes, regardless of the consent of the states.¹⁸¹ The goal of this pretextual final rule is to plan preferential policy and corporate-driven

projects regardless of states' support. One must also ask whether the extent to which this final rule requires prescriptive planning processes also limits the states' role to participate meaningfully when most are resource-strapped.

73. States did not join RTOs¹⁸² to pay for these preferential policy and corporate-driven projects. Rather, as I wrote in my concurrence to the NOPR, "States joined to provide their retail consumers with the promised benefits of lower transmission costs and strengthened reliability through regional planning of core Reliability projects."¹⁸³ I speak from personal experience. When I was a Commissioner at the Virginia State Corporation Commission, my colleagues and I considered applications to permit Virginia's major utilities to join PJM. The Virginia Commission's rules required us to examine "among other things, an [RTO's] reliability practices, pricing and access policies, and independent governance."¹⁸⁴ When we voted to approve the applications, PJM's planning for public policy projects that would be cost allocated regionally was not even on our radar.

b. The Final Rule Guts the States' Role in Cost Allocation as Proposed in the NOPR

74. Given the pretextual nature of this rule, it should not be surprising that it eviscerates the states' role in deciding cost allocation matters. NARUC strongly supported the NOPR's proposal to involve states in the cost allocation for Long-Term Regional Transmission Facilities and conversely disagreed with a requirement that transmission providers include a Long-Term Regional Transmission Cost Allocation Method in their OATTs without being obligated to seek agreement from the states.¹⁸⁵ NARUC explained:

[S]ince the projects under consideration in the Long-Term Regional Transmission Planning process are largely driven by state public policies, state regulators should have a key role in evaluating the benefits and allocating the costs. State regulators are attuned to the concerns of the local communities where the transmission will be sited and the retail ratepayers who must, in many instances, foot a large fraction of the cost.¹⁸⁶

Of course, to effectuate the pretextual agenda, the final rule simply ignores NARUC's entreaties and instead cuts the

¹⁷⁰ NOPR Concurrence at P 13 (emphasis in original).

¹⁷¹ NOPR, 179 FERC ¶ 61,028 at P 244; *see also* NOPR Concurrence at P 11 ("State approval is especially important in a multi-state region, where different states have different policies. The NOPR proposes to provide the maximum opportunity for creativity and flexibility to the states and regional entities in developing the process for designing and approving regional selection criteria and cost allocation arrangements.").

¹⁷² NOPR, 179 FERC ¶ 61,028 at P 246.

¹⁷³ *See* NOPR Concurrence at P 11; *see also supra* n.48.

¹⁷⁴ Final Rule, 187 FERC ¶ 61,068 at P 996 (emphases added).

¹⁷⁵ *Id.* P 999.

¹⁷⁶ *Id.* P 962 (emphasis added).

¹⁷⁷ *Id.* P 996.

¹⁷⁸ *Id.*

¹⁷⁹ *See supra* P 69.

¹⁸⁰ *See supra* Section I. Another example, of course, is micromanaging how local "stakeholder" meetings must be conducted, which, as noted, runs a strong risk of conflicting with state IRP proceedings and state authority. *See* Final Rule, 187 FERC ¶ 61,068 at PP 1625–1646. As above, I question whether prescriptive requirements to this degree can truly pass muster under court precedent.

¹⁸¹ And transmission providers themselves cannot even voluntarily account for states' input in the planning. Today's final rule requires that transmission providers *may not* include in their evaluation process or selection criteria any prohibition on the selection of a Long-Term Regional Transmission Facility based on the transmission providers' anticipated response of a state public utility commission or consumer advocates to particular Long-Term Regional Transmission Facilities. Final Rule, 187 FERC ¶ 61,068 at P 962.

¹⁸² I am aware that states *qua* states do not join RTOs/ISOs. Rather, they use their regulatory power to allow or require their regulated transmission-owning utilities to join.

¹⁸³ NOPR Concurrence at P 13.

¹⁸⁴ *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: In the matter concerning the application of Virginia Electric and Power Company d/b/a Dominion Virginia Power for approval of a plan to transfer functional and operational control of certain transmission facilities to a regional transmission entity*, Case No. PUE–2000–00551 (Nov. 10, 2004). The order included a stipulation in which Dominion agreed that joining PJM would not alter its legal obligation to seek a CPCN from the Virginia Commission to construct generation or transmission assets. *Id.*, Partial Stip. ¶ 6.

¹⁸⁵ NARUC Initial Comments at 45.

¹⁸⁶ *Id.* at 46 (citations omitted).

states out of any meaningful role in cost allocation.

75. First, the final rule essentially terminates the State Agreement Process by making the *ex ante* cost allocation method the default approach. While the NOPR proposed to require transmission providers to revise their OATTs to include *either* (1) an *ex ante* cost allocation method (*i.e.*, a Long-Term Regional Transmission Cost Allocation Method) to allocate the costs of Long-Term Regional Transmission Facilities, (2) a State Agreement Process, or (3) a combination thereof,¹⁸⁷ the final rule substantially modifies the NOPR proposal to require the use of one or more *ex ante* cost allocation methods.¹⁸⁸ Although the final rule permits transmission providers to include a State Agreement Process in their OATTs if the states agree, the final rule specifies that the State Agreement Process “cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities,”¹⁸⁹ and the final rule modifies the NOPR proposal to require an *ex ante* cost allocation method to apply as a backup.¹⁹⁰ The *ex ante* cost allocation method backup would apply if a State Agreement Process fails to result in a cost allocation method agreed to by Relevant State Entities and others *or if the Commission ultimately finds that the cost allocation method that results from a State Agreement Process is unjust, unreasonable, or unduly discriminatory or preferential.*¹⁹¹

76. Second, under the final rule, state consent on cost allocation is not required. The final rule explicitly declines to adopt the NOPR proposal to require transmission providers to seek the agreement of the states regarding the relevant cost allocation method to be applied to Long-Term Regional Transmission Facilities.¹⁹² Instead, the final rule merely requires transmission providers to establish a six-month Engagement Period “to provide a forum” for the states to negotiate an *ex ante* cost allocation method(s) and/or a State Agreement Process.¹⁹³ Under the final rule, if the negotiations fail, transmission providers must still file an *ex ante* cost allocation method(s).¹⁹⁴ Worse still, the final rule specifies that, even if the states *do* reach an agreement on an *ex ante* cost allocation method(s) and/or a State Agreement Process, the transmission providers *may ignore* it and file their own *ex ante* cost allocation method(s) instead.¹⁹⁵

Similarly, the final rule declines to require that, if the transmission providers disagree with a proposed cost allocation method agreed on by the states, transmission providers must file both cost allocation methods: the transmission providers’ preferred cost allocation method and the cost allocation method agreed to by the Relevant State Entities. So to the states, the final rule says, “Heads I win, tails you lose.”

77. Further, under the final rule, at the end of the Engagement Period, the states’ role—however small—in shaping an *ex ante* cost allocation formula is effectively over. NARUC argued that the Commission should provide some mechanism for future review of cost allocation methodologies for Long-Term Regional Transmission Facilities given that state public policies may evolve:

As the name suggests, these transmission facilities are expected to be planned over a longer period of time than projects built for reliability or economic reasons. States that do not currently have public policies requiring extensive transmission investments may forego an opportunity to participate in discussions regarding cost allocation, but their public policies may evolve over time. For the reforms proposed in this NOPR to be successful, the positions of relevant state entities should not be frozen in time.¹⁹⁶

But the final rule denies this request.¹⁹⁷ Further, the final rule specifies that transmission providers may file subsequent changes to their cost allocation method(s) *without establishing future Engagement Periods* beyond the initial one.¹⁹⁸

78. As noted above, the upshot of these changes, taken together, is that the states are simply cut out of any significant role in the cost allocation of the of Long-Term Regional Transmission Facilities. The final rule completely eviscerates the State Agreement Process and renders it non-viable. The final rule eliminates the core element of that approach—that states enter such cost allocation arrangements *voluntarily*. Now—with an *ex ante* cost allocation method that must serve as a backup in the event that the states’ negotiations fail, looming over the states’ heads like the sword of Damocles—the final rule gives states “an offer they can’t refuse,” telling the states that must they agree to a cost allocation or the transmission providers will impose one on them anyway. In such a circumstance, fruitful negotiation

between the states is virtually impossible, as states simply cannot say “no.” At the risk of stating the obvious, this forced cost allocation on the states is, of course, contrary to comments of NARUC and many of the individual states.¹⁹⁹

79. Just as concerning, as I discuss in Sections I and IV.B.2 of this dissent, the final rule will enable the ratepayers of non-consenting states to be assessed the cost of public policy projects of other states, which is anti-democratic and violates the basic principle of fairness. As NARUC points out, NARUC and individual state commissions supported the State Agreement Process to address this concern:

NARUC is particularly supportive of the State Agreement Process, which is similar to the PJM State Agreement Approach that has been approved by FERC and that NARUC and state commissions advocated to be included in the final rule. A state agreement approach allows states to further their public policy goals without burdening the ratepayers of states that have different priorities.²⁰⁰

The final rule’s gutting of the very State Agreement Process that NARUC supports as part of the final rule’s choice to ignore the consent of the states on cost allocation removes this key protection for the states and their ratepayers.

80. Further, given the final rule’s determinations undercutting the states’ role,

¹⁹⁹ See NARUC Initial Comments at 45 (“NARUC strongly supports the Commission’s proposal to involve states in cost allocation for Long-Term Regional Transmission Facilities and conversely explicitly rejects a requirement that public utility transmission providers include a Long-Term Regional Transmission Cost Allocation Method in their OATTs without being obligated to seek agreement from relevant state entities.”) (footnotes omitted); *see, e.g.*, Alabama Commission Initial Comments at 9 (“In other words, states may not force their preferences on their neighbors, or compel them to subsidize their achievement. Thus, it goes without saying that Alabama ratepayers should not be required to pay for transmission projects that are designed to promote or facilitate the public goals of other states, localities, or entities.”); West Virginia Commission Reply Comments at 2–3 (“The [West Virginia Commission] opposes any changes in transmission cost allocation that would require West Virginia customers, or customers of any State, to involuntarily pay for new transmission facilities that are needed to support the public policy generation choices of other States.”); North Carolina Commission and Staff Initial Comments at 15–16 (“The [North Carolina Commission and Staff] strongly support the NOPR proposals regarding cost allocation for regional transmission facilities developed through the Long-Term Regional Transmission Planning process, as that term is defined in the NOPR, specifically the requirement for transmission providers to seek state agreement on cost allocation methodologies and the requirement to create an opportunity for states to negotiate a cost allocation method after a transmission facility has been selected through the Long-Term Regional Transmission Planning process.”); Utah Commission Initial Comments at 9 (“[I]mposing a single set of federally mandated, highly prescriptive transmission planning and cost allocation requirements for the purpose of privileging the selection of costly transmission projects to serve remote and speculative renewable generation is not a lawful exercise of FERC’s authority under Section 206.”).

²⁰⁰ NARUC Initial Comments at 51 (footnote omitted).

¹⁸⁷ NOPR, 179 FERC ¶ 61,028 at P 302.

¹⁸⁸ Final Rule, 187 FERC ¶ 61,068 at P 1291.

¹⁸⁹ *Id.* PP 1292, 1361, 1404.

¹⁹⁰ *Id.* P 1292.

¹⁹¹ *Id.* P 1293.

¹⁹² *Id.* P 1354.

¹⁹³ *Id.* P 1357.

¹⁹⁴ *Id.* P 1367.

¹⁹⁵ *E.g., id.* P 1359 (“[T]he ultimate decision as to whether to file a Long-Term Regional Transmission Cost Allocation Method(s) and/or State Agreement Process to which Relevant State Entities have agreed will continue to lie with the transmission providers.”); *id.* P 1429 (“[A]fter the required Engagement Period, transmission providers in each transmission planning region will decide what Long-Term Regional Transmission Cost Allocation Method(s) and any State Agreement Process to file as part of their compliance filings. Therefore, transmission providers in a transmission planning

region could elect to propose on compliance a Long-Term Regional Transmission Cost Allocation Method and not file a State Agreement Process or other *ex ante* cost allocation method to which Relevant State Entities agreed. In addition, we do not impose any obligation on transmission providers to file a cost allocation method for Long-Term Regional Transmission Facilities with which they disagree, even if such a method were proposed to the transmission providers pursuant to a Commission-approved State Agreement Process, unless the transmission providers have clearly indicated their assent to do so as part of a Commission-approved State Agreement Process in their OATTs.”) (emphases added; footnote omitted); *see also id.* P 1356 n.2895 (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002) (*Atlantic City*)).

¹⁹⁶ NARUC Initial Comments at 49.

¹⁹⁷ Final Rule, 187 FERC ¶ 61,068 at P 1368.

¹⁹⁸ *Id.*

I highly doubt that PJM's State Agreement Approach or other existing mechanisms involving the states in other RTOs will remain viable with respect to the cost allocation of Long-Term Regional Transmission Facilities.²⁰¹ In addition to PJM's State Agreement Approach, NARUC notes that the country's other multi-state RTOs have mechanisms in place for the states to participate in regional transmission cost allocation:

In many regions, state regulators are at the forefront of successful efforts to coordinate regional transmission, including what many understand to be the most challenging issue, cost allocation. For instance, in SPP, the Regional State Committee has the primary authority for setting the basis of any regional cost allocation. In both MISO and ISO-New England, state committees have the ability to propose alternative cost allocation methodologies under some circumstances.²⁰²

81. Specifically, SPP has a Regional State Committee (RSC) process by which the RSC has agreed to a "highway-byway" *ex ante* cost allocation and SPP will file it,²⁰³ and MISO's Tariff provides that MISO will file under FPA section 205 OMS's alternative cost allocation to MISO's proposal.²⁰⁴ Given that the final rule's determination that transmission providers may ignore any agreement or alternative proposed by the states,²⁰⁵ such mechanisms could be called into question—unless the RTOs *voluntarily* agree to preserve them in their OATTs.²⁰⁶ If

²⁰¹ PJM's State Agreement Approach exemplified the proper way to involve states in decisions regarding cost allocation for public policy projects. The PJM State Agreement Approach was not directed by Order No. 1000, but rather by PJM's own voluntary act of reaching out to the states in PJM States and asking PJM States to propose a cost allocation for public policy projects. PJM accepted PJM States' proposal—which became the PJM State Agreement Approach—and submitted it to FERC in its compliance filing. It was accepted by FERC, but as today's final rule shows, only grudgingly and only until the chance came to extinguish it.

²⁰² NARUC Initial Comments at 46 (citing MISO Transmission Owners Agreement, Appendix K, Article II, Section ILE.3.b (providing regional state committee with the opportunity to develop and request MISO file an alternative cost-allocation methodology under certain circumstances); ISO New England, Agreements and Contracts, Transmission Operating Agreement, Section 3.04 (h)(vi)(A–C) (providing regional state committee with opportunity to provide alternative cost allocation proposal in connection with certain transmission cost allocation provisions in ISO–NE's tariff)).

²⁰³ See SPP, Governing Documents Tariff, § 7.2 (Bylaws 7.2 Regional State Committee) (2.0.0); see also *Sv. Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 219, *order on reh'g*, 109 FERC ¶ 61,010, at PP 93–94 (2004); *Entergy Arkansas, Inc.*, 133 FERC ¶ 61,211, at P 15 (2010).

²⁰⁴ *E.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,165, at PP 30–31 (2013) (citations omitted).

²⁰⁵ See, e.g., Final Rule, 187 FERC ¶ 61,068 at PP 1359, 1429; see also *id.* P 1356 n.2895 (citation omitted).

²⁰⁶ See, e.g., *id.* P 1412 ("[N]or do we create any obligation that transmission providers file a cost allocation method resulting from a State Agreement Process, unless the transmission providers had clearly indicated assent to do so in their OATTs); *id.* n.3013 ("[T]ransmission providers may

these mechanisms are weakened, or even eliminated, the only alternatives left for the states to shape the RTOs' cost allocation would be to file comments to the RTOs' cost allocation filings or to file a section 206 complaint—no different than any RTO stakeholder.

82. The final rule acknowledges that "experience with Order No. 1000 has reinforced the critical role that states play in the development of new transmission infrastructure, particularly at the regional level, where transmission projects may physically span, and their costs may be allocated across, multiple states."²⁰⁷ However, the final rule's determinations on cost allocation undercut this critical role. It appears obvious that the final rule does not in fact view the states as partners in a cooperative federal system, but rather as potential obstacles to its pretextual political, corporate, and ideological agendas.

83. The final rule sets forth two central arguments for its dramatic reduction of the states' role. First, the final rule suggests that, per *Atlantic City*,²⁰⁸ the Commission cannot deprive transmission providers of their FPA section 205 filing rights to propose tariff changes to rates.²⁰⁹ And second, the final rule claims that if transmission providers were permitted to rely solely on a State Agreement Process to determine the cost allocation and that process were to fail, "there would be no cost allocation method for Long-Term Regional Transmission Facilities selected as the more efficient or cost-effective solutions to Long-Term Transmission Needs," and "[a]s a result, such selected Long-Term Regional Transmission Facilities would be less likely to be developed, and the benefits that these facilities would provide would not be realized."²¹⁰ Both arguments are without merit.

i. The Final Rule Takes Far Too Broad a View of *Atlantic City*

84. *Atlantic City* is often discussed as a bar to FERC's ability to take meaningful action on many issues, including transmission cost allocation.²¹¹ But *Atlantic City* does not stand for an outright prohibition on Commission action, especially under FPA section 206, under which this pretextual rule purports to act. All *Atlantic City* stands for is that "transmission-owning utilities have 'filing rights' under section 205 that FERC may not *revoke*."²¹² *Atlantic City* does not prevent FERC from granting additional filing rights to other entities, including *state*

voluntarily agree as part of a State Agreement Process in their OATTs that transmission providers shall file any cost allocation method that meets the requirements of their State Agreement Process, even if those transmission providers do not agree with that method.").

²⁰⁷ *Id.* P 124.

²⁰⁸ 295 F.3d 1.

²⁰⁹ *E.g.*, Final Rule, 187 FERC ¶ 61,068 at P 1363 & n.2909; *id.* P 1356 n.2895.

²¹⁰ *Id.* P 1293.

²¹¹ 295 F.3d at 9–11.

²¹² See also Peskoe Article at 572 (emphasis added), a thorough and helpful distillation of the intricacies of FPA sections 205 and 206 as to RTO governance. See also *id.* at 567.

regulators, if it determines that existing practices, including RTO independence, are unjust and unreasonable and unduly discriminatory or preferential.²¹³

85. In a similar vein, *Atlantic City* does not require FERC to force non-consenting states to pay for other states' policy projects, as today's final rule implies.²¹⁴ The final rule's reliance on *Atlantic City* in this regard is simply a way for FERC to sidestep action that will truly ensure that needed transmission gets built with the cooperation, support, and assent of the states. Instead, what we have in today's final rule is a patent instance of regulatory capture with the singular goal to build out preferential policy and corporate-driven projects, steamrolling the states and consumers alike. And to be clear, nothing meaningfully prevents the NOPR compromise that would have maintained or elevated the states' role in transmission planning and cost allocation even further. In fact, even accounting for *Atlantic City*, the NOPR compromise was a worthwhile solution to getting the transmission that is *actually* needed to serve organic load built.

ii. The Commission Fails Consumers by Unreasonably and Unfairly Socializing Policy- and Corporate-Driven Costs Across Captive Customers

86. The final rule's claim that the Long-Term Regional Transmission Facilities selected are "the more efficient or cost-effective solutions to Long-Term Transmission Needs"²¹⁵ is disingenuous. As I discuss above in Section I, in a sleight of hand move, the final rule lumps together in one bucket for planning and for cost allocation purposes projects that address policy-driven and corporate-driven needs with those that address reliability and economic needs. The final rule's goal is to socialize the costs associated with preferential policy and corporate-driven projects across the multi-state regions, even when the states have never consented for their consumers to pay for such projects. But

²¹³ See *id.* at 614–615 ("To bolster RTO independence, FERC could expand filing rights over regionally significant issues that are currently controlled by the [investor-owned utilities (IOUs)], such as *cost allocation for regional transmission expansion*. . . . State regulators are also potential beneficiaries. State utility commissions comprehensively regulate IOUs' local service and are familiar with IOUs' local operations and planning. *State filing rights might serve a consumer protection function, as state regulators are ultimately responsible for ensuring that retail rates, which include costs of RTO-planned transmission projects and RTO-administered markets, appropriately account for consumers' interests*. As noted, MISO and SPP agreements already provide state regulators with limited filing rights over transmission cost allocation or resource adequacy, two areas where states have overlapping oversight *Providing states with meaningful roles in RTO processes might mitigate future conflicts between states' priorities and RTO rules and planning processes.*") (emphases added) (footnotes omitted). Let me add my strong endorsement to granting states section 205 filing rights with respect to cost allocation. The final rule, of course, goes in the opposite direction.

²¹⁴ See *e.g.*, Final Rule, 187 FERC ¶ 61,068 at PP 1356 n.2895, 1429–1431.

²¹⁵ *Id.* P 1293.

requiring the ratepayers of a non-consenting state to pay for the public policy projects of another state cannot reasonably be deemed “efficient” or “cost-effective.”

2. The Final Rule Requires Consumers in Non-Consenting States To Pay the Costs of Other States’ Public Policy Projects

a. The Costs of Public Policy-Driven Projects Must Not Be Imposed on Non-Consenting Consumers Without State Regulatory Oversight

87. In my NOPR Concurrence, I noted that “no individual state’s consumers can be forced to bear the costs of another state’s policy-driven project or element of a project against its consent.”²¹⁶ I have adamantly maintained this position in subsequent Statements:

The costs related to a public policy project . . . should be borne by the sponsoring state and not shifted to consumers in other states without the consent of responsible officials in those states, who can then be held accountable by the voters of that state for their decisions (as can officials in the sponsoring state). That is how democracy is supposed to work.²¹⁷

I have explained that if the people and businesses of the sponsoring state do not like the impacts of their state’s public policies, “their recourse is to the ballot box,”²¹⁸ but that in contrast, “[c]onsumers in other states do not have such recourse, which is why these costs must be confined to [the sponsoring state].”²¹⁹

88. I have written before that “imposing the costs of a project driven by one state’s public policies onto another state that has not consented to such cost allocation would, in my view, presumably result in unjust and unreasonable rates.”²²⁰ Such imposition

would be contrary to basic fairness, a core principle of American democracy:

For if democracy means anything at all, it means that the people have an inherent right to choose the legislators to whom the people grant the power to decide the major questions of public policy that impact how the people live their daily lives. . . . That is the basic constitutional framework of the United States and it is the same for any liberal democracy worth the name.²²¹

The final rule subverts this principle.²²²

b. Certain States Are Not “Cost Causers” for Cost Allocation Purposes

89. Today’s final rule provides very little in the way of support for its cost allocation requirements, despite the extensive changes to planning requirements.²²³ This final rule simply assumes that it is on sound footing as to cost causation. But that is not the case. While *some* precedent cited by today’s final rule sheds some indirect light on the cost allocation issues implicated here,²²⁴ at its core, today’s final rule involves a new application of the cost causation principle to justify the final rule’s pretextual agenda. It intends to force consumers in one state to pay for the costs of public policies enacted by politicians in another state and corporate purchasing preferences. But those costs and the resulting rates cannot be considered just and reasonable in any universe.

90. We are at the point where we must argue that not *all* consumers in certain states are “cost causers” simply because they have joined a multi-state RTO or fall within a transmission planning region. These consumers are not the “but for” cause of many of the Long-Term Transmission Needs required by the consideration of the specified categories of factors in today’s policy agenda-driven rule. Nor are such consumers the intended beneficiaries of public policies in states enacted by politicians for whom they never voted. Indeed, absent rational limits on

been able to locate no evidence in the record that the New York policies at issue in today’s order are causing cost-shifting onto consumers in other states. *If consumers in other states were disadvantaged, I may well view this matter differently.*”) (emphasis added), <https://www.ferc.gov/news-events/news/item-e-2-commissioner-mark-c-christie-concurrence-regarding-new-york-state-public>; cf. Commissioner Mark C. Christie, Fair RATES Act Statement on PJM Minimum Offer Price Rule (MOPR) Revisions, Docket No. ER21–2582–000 at P 6 (Oct. 19, 2021) (“I would have proposed that PJM formulate a replacement for the current MOPR based on three broad principles: (1) a state may designate specific or categorical resources as ‘public policy resources’ and such designated resources will be funded through a mechanism *chosen by the state* outside of the capacity market . . . and (3) *non-sponsoring state consumers would not be forced to pay for another state’s designated public-policy resources.*”) (footnotes omitted) (emphasis in the original and added), <https://www.ferc.gov/news-events/news/commissioner-christies-fair-rates-act-statement-pjm-mopr>.

²²¹ Certificate Dissent at P 63.

²²² *Infra* Section IV.B.2.b.

²²³ See, e.g., Final Rule, 187 FERC ¶ 61,068 at PP 266, 269, 279, 1304, 1478–1479.

²²⁴ As an aside, I question whether some of the precedent cited by today’s final rule in support of the cost causation issue is truly apposite when you look at the facts in those cases.

the “free rider” concept that the cost causation principle is meant to address, anyone can be deemed a beneficiary of any transmission project anywhere.

91. That policy-caused costs cannot be attributed to consumers who did *not* cause the policy is consistent with case law. As articulated mostly clearly by the D.C. Circuit, the cost causation principle means that “all approved rates [must] reflect to some degree the costs *actually caused* by the customer who must pay them.”²²⁵ This has been oft repeated by many courts over the years, including most notably the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) in *Illinois Commerce Commission v. FERC*.²²⁶ The Seventh Circuit expanded on this further to state that, “[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have ‘caused’ a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.”²²⁷

92. Tied to the cost causation principle is the concept of “free ridership.” As explained by the Commission in Order No. 1000–A, a free rider is an “entity is not required to pay for a benefit it receives”²²⁸ and is the form of “subsidization” against which the cost causation principle is supposed to protect.²²⁹

93. As explained in Order No. 1000–A, the Commission treats each transmission customer not as using a single transmission path but rather as usual the entire transmission system and views such service as service over the entire grid.²³⁰ The Commission explained:

Given the nature of transmission operations, it is possible that an entity that uses part of the transmission grid will obtain benefits from transmission facility enlargements and improvements in another part of that grid regardless of whether they have a contract for service on that part of the grid and regardless of whether they pay for those benefits. This is the essence of the “free rider” problem the Commission is seeking to address through its cost allocation reforms. Any individual beneficiary of a new transmission facility has an incentive to defer investment in the anticipation that other beneficiaries in the region will value the project enough to fund its development. This can lead to situations in which no developer moves forward, adversely affecting development of transmission facilities and, as a result, rates for jurisdictional services.²³¹

Therefore, the Commission explained that the cost allocation provisions of Order No. 1000 (the failures of which allegedly justify the changes contemplated by today’s final rule), which seek to allocate costs to beneficiaries in a region roughly commensurate with benefits they receive, were consistent with the statement in *ICC*

²²⁵ *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (emphasis added).

²²⁶ 576 F.3d 470, 476 (7th Cir. 2009) (*ICC*).

²²⁷ *Id.*

²²⁸ Order No. 1000–A, 139 FERC ¶ 61,132 at P 573.

²²⁹ *Id.* P 578.

²³⁰ *Id.* P 560 (citations omitted).

²³¹ *Id.* P 562 (internal citation omitted).

²¹⁶ NOPR Concurrence at P 12 (citing NOPR, 179 FERC ¶ 61,028 at PP 302, 312).

²¹⁷ *N.Y. Power Auth.*, 185 FERC ¶ 61,102 (2023) (Christie, Comm’r, concurring at P 2), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-nypas-abandoned-plant-incentive-el23>; *N.Y. Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,004 (2022) (Christie, Comm’r, concurring at P 2).

²¹⁸ E.g., *N.Y. Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,101 (2022) (Christie, Comm’r, concurring at P 5), <https://www.ferc.gov/news-events/news/item-e-2-commissioner-mark-c-christie-concurrence-regarding-new-york-independent>.

²¹⁹ *N.Y. Indep. Sys. Operator, Inc.*, 186 FERC ¶ 61,184 (2024) (Christie, Comm’r, concurring at P 2).

²²⁰ *NSTAR Elec Co.*, 179 FERC ¶ 61,200 (2022) (Christie, Comm’r, concurring at P 10), <https://www.ferc.gov/media/e-13-er22-1247-000>; see also *N.Y. Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,101 (Christie, Comm’r, concurring at P 6) (“A similar analysis could well lead to a different outcome in a multi-state RTO, if the record showed that the RTO was implementing one state’s public policies as to preferred resources, and that implementation resulted in impacts being shifted to consumers in one or more other states in the multi-state RTO. Such impacts and cost-shifting in multi-state RTOs, if proven by the record, could well be unjust, unreasonable and unduly discriminatory or preferential under the FPA.”) (emphasis in the original and added); *N.Y. Pub. Serv. Comm’n v. N.Y. Indep. Sys. Operator, Inc.*, 174 FERC ¶ 61,110 (2021) (Christie, Comm’r, concurring at P 3) (“I note that the NYISO is a single-state ISO and I have

that “[a]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them.”²³² Indeed, all of the precedent relied upon in today’s final rule signals that free ridership is a concern solely based on the assumptions underlying the transmission planning. And herein lies the deception—the more you plan and account for, the bigger and more regionalized you can argue the cost allocation framework should be. Which makes sense when the goal of today’s final rule is to enact a sweeping policy agenda and thus socialize the costs across consumers in a multi-state region.

94. The main support for the cost causation principle is *ICC*,²³³ for the exact quote noted above. However, often omitted from the discussion of *ICC* is the context and outcome of the case. In that case, the Seventh Circuit remanded the Commission’s approval of cost allocation concerning “Project Mountaineer”²³⁴ (yes, the same one that prompted PATH) for lack of substantial evidence regarding the FERC-approved cost allocation. In addition to the quote above, the Seventh Circuit also expressed the following: “FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members.”²³⁵ And it merits repeating that “[t]o the extent that a utility benefits from the costs of new facilities, it may be said to have ‘caused’ a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.”²³⁶

²³² *Id.* P 565 (citing *ICC*, 576 F.3d 470 at 476) (alterations in the original). In Order No. 1000, the Commission also found that “[b]eneficiaries in one state are not subsidizing anyone in another state when they are allocated costs that are commensurate with the benefits that accrue to them, even if the transmission facility in question was built in whole or part as a result of the other state’s transmission needs driven by Public Policy Requirements.” Order No. 1000, 136 FERC ¶ 61,051 at P 545. “If no benefits accrue, the cost allocation principles we adopt below would prohibit the allocation of costs to the non-beneficiaries. If benefits do accrue, however, there are no less benefits because Public Policy Requirements played a role in the decision to construct the transmission facility.” *Id.* While Order No. 1000 may have successfully established this to be the case, per *South Carolina*, today’s final rule is not similarly situated to Order No. 1000 with its required minimum benefits, selection criteria, and utter disregard of the states’ role in planning and cost allocation. See *supra* Section III.A. Today’s final rule instead creates beneficiaries for projects that are primarily public policy-driven, based on the categories of factors required to be considered in today’s final rule’s planning requirements.

²³³ 576 F.3d 470.

²³⁴ See PATH Concurrence at P 4 (providing a history on Project Mountaineer). Relying on a case that remanded the Commission’s approval of cost allocation associated with a regional transmission project that never came to fruition is nothing short of ironic.

²³⁵ *ICC*, 576 F.3d at 476 (emphasis added).

²³⁶ *Id.* (emphasis added). See NARUC Initial Comments at 33–34 (“Long-Term Regional Transmission Planning must recognize that benefits inherently become more speculative as the planning horizon increases. Additionally, planning based on

So, given the extent to which the Long-Term Transmission Needs contemplated by today’s final rule factor in state public policies and special interests’ goals, you would expect the only beneficiaries for cost allocation purposes to be states with those public policies or other special interest drivers of the transmission.

95. Unfortunately, you would be wrong. Due to the final rule requiring planning for any and every transmission need and mandating minimum reliability and economic benefits as part of the planning process, projects developed primarily for preferential policy and corporate purposes will necessarily have the broadest array of so-called beneficiaries possible, all identified prior to selection.²³⁷ These so-called beneficiaries will then be forced to pay for these projects, simply because they may receive some trivial benefits due to their participation in a regional transmission system. These so-called beneficiaries will be treated as “cost causers” even though their contributions *do not* ensure the projects get built nor ensure that the projects are not delayed. Today’s final rule, of course, even emphasizes that, as to why today’s final rule does not require the consideration of public policy benefits, it “does not allow allocation of costs based on benefits to entities that do not receive benefits or receive only trivial benefits in relationship to costs of those transmission facilities.”²³⁸ But this is because today’s final rule already determined the minimum reliability and economic benefits that all projects contemplated by the final rule must have. Adding in public policy benefits would shift the resulting cost allocation to show the *actual* beneficiaries—the states with preferred policies and corporate and special interests. So, through a mismatch in planning criteria and benefits, today’s final rule ensures socializing the costs of preferential policy and corporate-driven projects onto states and consumers

public policy objectives must be transparent about identifying projects that would not be selected but for those public policy objectives. *Benefits assigned to projects must recognize these principles.*”) (emphasis added).

²³⁷ See *supra* Sections I, III.A.; see also Final Rule, 187 FERC ¶ 61,068 at P 965.

²³⁸ Final Rule, 187 FERC ¶ 61,068 at P 1515. This is why I have described this final rule as a shell game with respect to the issue of the benefit mismatch between planning and costs. By making the minimum required benefits reliability- and economic-focused, today’s final rule ensures that the “beneficiaries” are those that are receiving some reliability and economic benefits. As we know from basic transmission planning, *any* transmission built is going to bring some reliability and economic benefits. So, any transmission planned through Long-Term Regional Transmission Planning for the identified Long-Term Transmission Needs will necessarily bring some reliability and economic benefits. And by *not* requiring a matching of benefits to the Long-Term Transmission Needs that are planned for, in this case public policy benefits, the resulting benefits of any one project will be skewed to indicate more “beneficiaries” than there would be if today’s final rule accounted for public policy benefits separately. See NARUC Initial Comments at 33–34. If today’s final rule accounted for public policy benefits or corporate goals separately, it would be clear who the *actual* drivers, and *actual* beneficiaries, of any one project are.

that will ultimately receive trivial benefits, in violation of *ICC*. If you find all this confusing, the final rule is intended to be. That’s why it’s a shell game.

96. At its core, *ICC* is simply a baseline regarding the cost causation principle’s application. That is, the Commission cannot require cost allocation to a particular group of utilities, *i.e.*, consumers, where there is *no* evidence of benefits. Its findings should not be distorted, as today’s final rule suggests through Orwellian newspeak, to support a mismatch of planning criteria to benefits to strongarm a cost allocation regime to get preferential policy and corporate-driven projects built.

97. Also referenced by today’s final rule for cost causation is *South Carolina*.²³⁹ In the context of cost causation, the D.C. Circuit concluded that “the Commission’s adoption of a beneficiary-based cost allocation method is a logical extension of the cost causation principle.”²⁴⁰ The court added that it had “endorsed the approach of ‘assign[ing] the costs of system-wide benefits to all customers on an integrated transmission grid.’”²⁴¹

98. The final rule does not simply require a beneficiary-based cost allocation, like Order No. 1000. Instead, as I *must continue to emphasize*, it requires mandating reliability and economic benefits during the planning process to shoehorn the broadest group of beneficiaries possible for projects that do not remotely relate to reliability and economic needs.²⁴² This is not a “light touch” that “does not dictate how costs are to be allocated.”²⁴³ Today’s final rule may attempt to sequester the beneficiaries of these reliability and congestion benefits from the cost allocation “benefits” by not clearly linking the two,²⁴⁴ but in what reality will a transmission provider seeking to comply with today’s final rule identify *different* beneficiaries from those identified in the planning process? The result of this shell game is to ensure preferential policy and corporate-driven projects are selected with the widest group of beneficiaries possible, so as to socialize the costs across the widest group of consumers.²⁴⁵

²³⁹ 762 F.3d 41.

²⁴⁰ *Id.* at 85.

²⁴¹ *Id.* (citations omitted).

²⁴² See *supra* Sections I, III.A.

²⁴³ See *South Carolina*, 762 F.3d at 81; see also *supra* Section III.A.

²⁴⁴ See, e.g., Final Rule, 187 FERC ¶ 61,068 at P 1506 (“We do not require that any particular benefit used in the evaluation and selection of Long-Term Regional Transmission Facilities be reflected in a Long-Term Regional Transmission Cost Allocation Method filed with the Commission.”). This provision illustrates the confusing and contradictory nature of the final rule and provides another example of the shell game.

²⁴⁵ Today’s final rule relies on several other cases in support of its oversimplification of the cost causation principle, such as *Old Dominion Electric Coop. v. FERC*, 898 F.3d 1254 (D.C. Cir. 2018), and *Long Island Power Authority v. FERC*, 27 F.4th 705 (D.C. Cir. 2022), among others, but the same is true of these cases—the Commission cannot strong-arm beneficiaries to get transmission built, and override the states to do so. Of course, this is primarily a problem in multi-state RTOs, but overriding the states with regulation based on a cooperative federalism statute is not in good faith and the result is terrible for consumers everywhere.

99. Today's final rule ultimately presents the wrong solution to the perceived problem of "balkanized" transmission planning.²⁴⁶ Unfortunately, today's final rule devises the shell game to ensure that the biggest planning bucket means the biggest pool of potential beneficiaries. And to carry out the shell game, the final rule walks back cost allocation principle (6) because, without this change, today's final rule's preferred cost allocation framework does not work.²⁴⁷

100. NARUC and many individual states oppose the Commission's imposition of mandatory minimum benefits and would prefer a bottom-up rather than a top-down approach: "The proposed list of benefits for consideration is a better way to accomplish the objectives of the NOPR than specification of benefits that must always be used in Long-Term Regional Transmission Planning."²⁴⁸ Today's final rule blithely brushed these concerns aside.

101. To effectuate purported compliance with the cost causation principle, today's final rule ignores the principle of the *optimal solution* in transmission planning. For each identified reliability problem, there is an optimal solution that solves the reliability problem at the *least* cost to consumers. For an economic project, consumers should receive the *maximum* reduction in congestion costs relative to the cost of the project, or put in another way, for a given reduction of congestion costs, consumers should pay the *least* costs for the project. The final rule, by contrast, claims that a project that is driven by one state's public policies will still provide some reliability and congestion benefits to other states, so consumers in those states *must* be treated as beneficiaries.²⁴⁹ But even assuming that consumers in those other states hypothetically receive some marginal reliability or congestion benefits, they are

being overcharged for those benefits because the project includes the costs of another state's public policies or costs of projects to meet corporate goals, and the only benefits required to be considered by today's final rule are reliability and economic benefits. Consumers in the non-policy causing states are not receiving or paying for the optimal solution to an identified reliability problem or maximum congestion relief compared to the costs they are being forced to pay. As a consequence, the transmission *rates*—let's ignore the planning practices for a moment—they will be forced to pay are clearly unjust and unreasonable under the FPA.

3. The Final Rule Violates the Commission's Consumer Protection Duty Under the FPA

102. To add to the number of already unjust and unreasonable aspects in today's final rule, today's final rule is patently unfair to consumers. That much is apparent from its decision, through transmission planning and cost allocation processes: (1) to shift interconnection costs from generation developers to consumers through transmission planning, and (2) to shift the costs of, *inter alia*, a transmission project accommodating a corporate commitment from corporate consumers to other consumers. Today's final rule, equally harmful to consumers, walk backs the NOPR proposal to remove the CWIP Incentive, one of the major reasons I supported the NOPR in the first place. The final rule essentially uses the justification of efficiency and cost-effectiveness to create catastrophic outcomes for consumers. Such an anti-consumer outcome is simply unjust and unreasonable, and in this case, even unduly discriminatory and preferential.

a. The Final Rule Unlawfully Shifts Interconnection Costs From Developers to Consumers

103. In prior statements, I have frequently discussed the basic principle that generation developers should pay the costs to interconnect their generators to the grid:

[G]eneration developers in RTOs should pay the full "but for" costs of their interconnection, including network upgrades. Consumers (*i.e.*, load) should not pay one nickel. They are not the ones seeking to profit from the interconnection. New generation in RTOs is supposed to be driven by the market, not by integrated resource planning, as in non-RTOs. This is the compelling principle underlying participant funding of interconnection in RTOs.²⁵⁰

²⁵⁰ See *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,190 (2023) (Christie, Comm'r, concurring at P 2), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-mpfca-order-concerning-funding>; *Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,156 (2023) (Christie, Comm'r, concurring at P 2), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-gia-order-concerning-funding>; *Midcontinent Indep. Sys. Operator, Inc.*, 183 FERC ¶ 61,113 (2023) (Christie, Comm'r, concurring at P 2), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-fsa-order-concerning-funding>; *Midcontinent Independent System Operator, Inc.*, 182 FERC ¶ 61,225 (2023) (Christie, Comm'r, concurring at P 2), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-miso-mpfca-and-fsa-orders-concerning-funding>; see also *Midcontinent Indep. Sys. Operator, Inc.*, 185 FERC ¶ 61,182 (2023), *order on reh'g*, 187 FERC ¶ 61,015 (2024), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-order-rejecting-miso-gia-concerning-funding>. This principle also applies to developers of merchant transmission lines who seek to interconnect.

By requiring the coordination of regional transmission planning and generator interconnection processes and by requiring the incorporation of Factor Category Six: generator interconnection requests and withdrawals in the development of Long-Term Scenarios, the final rule causes consumers to subsidize generation developers and thus subverts this basic principle.

i. Coordination of Regional Transmission Planning and Generator Interconnection Processes Will Result in Unlawful Cost Shifts to Consumers

104. The final rule requires transmission providers in each transmission planning region to revise their existing Order No. 1000 regional transmission planning processes to evaluate for selection regional transmission facilities that address certain identified interconnection-related transmission needs associated with certain interconnection-related network upgrades originally identified through the generator interconnection process.²⁵¹ As a result of this requirement, transmission providers may select in regional transmission plans for purposes of cost allocation transmission facilities designed to address certain interconnection needs and *will allocate the costs of such facilities to the load in that region*. This practice will force consumers to subsidize the interconnection costs of generator developers and in so doing turn them into the banks for the ventures, viable or otherwise, of generation developers—a classic example of the socialization of costs to enable private profit. Of course, this will result in rates that are blatantly unjust, unreasonable, unduly discriminatory and preferential.

105. The final rule's attempted justifications for this effort to shift interconnection costs to consumers are vacuous and fail to disguise the real agenda, which is to subsidize developers of preferred

events/news/commissioner-christies-concurrence-miso-mpfca-and-fsa-orders-concerning-funding; see also *Midcontinent Indep. Sys. Operator, Inc.*, 185 FERC ¶ 61,182 (2023), *order on reh'g*, 187 FERC ¶ 61,015 (2024), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-order-rejecting-miso-gia-concerning-funding>. This principle also applies to developers of merchant transmission lines who seek to interconnect. *Midcontinent Indep. Sys. Operator, Inc.*, 181 FERC ¶ 61,218 (2022) (Christie, Comm'r, concurring at P 1), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-concerning-funding-interconnection-costs-rtos>. If state regulators in a multi-state region agreed on a different cost allocation related to interconnection costs that they believed protected consumers from unfair treatment, then such alternative would merit consideration.

²⁵¹ Final Rule, 187 FERC ¶ 61,068 at PP 1106–1107, 1126, 1145. Specifically, the final rule requires transmission providers to evaluate for selection regional transmission facilities to address interconnection-related transmission needs that have been identified in the generator interconnection process as requiring interconnection-related network upgrades where, *inter alia*, "an interconnection-related network upgrade identified to meet those interconnection-related transmission needs has a voltage of at least 200 kV and an estimated cost of at least \$30 million." *Id.* P 1145 (emphasis in original).

²⁴⁶ See *supra* Section IV.A.

²⁴⁷ See Final Rule, 187 FERC ¶ 61,068 at P 1474.

²⁴⁸ See NARUC Comments at 25; see also New York Commission and NYSEDA Initial Comments at 7 ("We urge the Commission to ensure that any final rule in this proceeding is sufficiently flexible to accommodate regional differences and avoid disrupting the processes already in place and otherwise underway in New York that are working well for the region."); SPP Initial Comments at 18 ("How and when transmission benefits are calculated and incorporated in any regional transmission planning assessment should be at the discretion of each public utility transmission provider and its stakeholders. This would allow for agility in process decisions to balance the value the analysis provides with the burden of the effort."); ISO-NE Initial Comments at 5 ("Individual regions should be permitted to determine the benefits that will lead to transmission in the region."); NYISO Initial Comments at 39 ("The final rule should confirm that each planning region is not required to use the specific benefits described in the NOPR While, in practice, the NYISO already uses most of the 12 illustrative benefits identified in the NOPR, the NYISO should be permitted to retain its flexibility to identify, with input from state entities and stakeholders, the benefits used in its processes and how such benefits are calculated."); *id.* at 11 ("The final rule should not mandate strict requirements concerning how long-term transmission planning must be conducted.").

²⁴⁹ Final Rule, 187 FERC ¶ 61,068 at Section III.D.1.c.

resources. For example, the final rule asserts that reforms are necessary because “it may be more efficient or cost-effective to address [interconnection-related transmission needs] through the regional transmission planning and cost allocation process.”²⁵² The final rule professes that its requirements “will result in selection of more efficient or cost-effective regional transmission solutions that will provide benefits to the transmission system, cost allocation for such regional transmission facilities that is at least roughly commensurate with estimated benefits, and elimination of a barrier to entry for new generation resources (which will enhance competition in wholesale electricity markets and facilitate access to lower-cost generation).”²⁵³ But more efficient or cost-effective for whom? Certainly not for consumers who will be conscripted to subsidize tens or hundreds of millions of dollars of interconnection costs so that generator developers may more cheaply interconnect and make higher profits (and likely receive government subsidies). The final rule’s speculation that extracting such subsidies from consumers will “facilitate access to lower-cost generation” is purely pretextual.

106. The final rule notes that “the Commission has found, and courts have affirmed, that interconnection-related network upgrades identified in the generator interconnection process can provide widespread transmission benefits that extend beyond the interconnection customer.”²⁵⁴ Further, it asserts that the regional transmission facilities designed to address the interconnection needs “may have the potential to provide more widespread benefits to transmission customers.”²⁵⁵ Today’s final rule does not even come close to justifying the enormous cost shifts this will place on consumers.

107. The final rule summarily brushes aside the concern that its reform will shift interconnection costs from interconnection customers (*i.e.*, generation developers) to load.²⁵⁶ It explains that “[t]ransmission providers will still have to evaluate and select any regional transmission facilities that address the interconnection-related transmission needs as the more efficient or cost-effective regional transmission solution as part of the regional transmission planning process in order for any regional cost allocation method to apply.”²⁵⁷ The final rule also explains that “if such a facility is selected, the Commission-approved *ex ante* regional cost allocation method for that facility would allocate its costs at least roughly commensurate with its estimated benefits.”²⁵⁸ But the regional cost allocation methods allocate cost only to load, not to generation. So, how could allocating interconnection costs to load enable them to be “roughly commensurate to benefits” when generator developers, the primary

beneficiaries of the transmission facilities and the “*but for*” cause of their development be allocated nothing? Here, as elsewhere, the final rule deviates from the FPA’s consumer protection purpose: under the final rule, rather than generation existing to serve load, load is being conscripted to serve (the profits) of generation.

108. Finally, the final rule’s conclusion that it will not incentivize gaming by interconnection customers to include interconnection-related network upgrades in the regional transmission planning process is detached from reality.²⁵⁹ The final rule notes that interconnection requests require significant financial commitments from the interconnection customer (*e.g.*, application fees, study deposits, and site control requirements) and that interconnection customers employing such a strategy would face several risks.²⁶⁰ As with so much FERC does, today’s final rule woefully underestimates at its peril the profit-seeking, and at times, gambling behavior of generator developers. In issuing this final rule, the Commission appears to forget that a main driver in issuing Order No. 2023 was to *reduce* speculative interconnection requests and interconnection request withdrawals spurred by this behavior.²⁶¹ Despite the significant financial commitments and risks that the final rule describes, I can foresee generators submitting speculative or spurious interconnection requests in the efforts to be subsidized by load if the estimated interconnection costs are high enough. In any event, I think it obvious that, *ceteris paribus*, the final rule will encourage more disruptive *withdrawals*—particularly for requests that necessitate high interconnection costs—as the final rule provides generator developers dissatisfied with high interconnection costs a chance at another bite at the apple. And of course, apples taste sweeter when they’re paid for by someone else.

ii. Factor Category Six Will Result in Unlawful Cost Shifts to Consumers

109. For similar reasons, I oppose the final rule’s requirement that transmission providers in each transmission planning region incorporate in the development of Long-Term Scenarios, Factor Category Six: interconnection requests and withdrawals.²⁶² Such a requirement would ultimately result in consumers paying for the transmission that generators need to interconnect to the grid. This again is a way to cost shift interconnection costs from generation developers to consumers.

²⁵⁹ See *id.* PP 1119–1120.

²⁶⁰ *Id.* P 1119.

²⁶¹ See, *e.g.*, Order No. 2023, 184 FERC ¶ 61,054 at P 47 (stating that the existing serial first-come, first-served study process “create[d] incentives for interconnection customers to submit exploratory or speculative interconnection requests pursuant to which interconnection customers seek to secure valuable queue positions as early as possible, even if they are not prepared to move forward with the proposed generating facility. Such generating facilities are often not commercially viable and, thus, the interconnection customers ultimately withdraw from the interconnection queue.”).

²⁶² See Final Rule, 187 FERC ¶ 61,068 at P 472.

b. Factor Category Seven Forces Some Consumers To Subsidize Others

110. The Commission’s requirement that transmission providers incorporate Factor Category Seven, utility and corporate commitments and federal, federally-recognized Tribal, state, and local goals that affect Long-Term Transmission Needs, in the development of Long-Term Scenarios²⁶³ is unjust and unreasonable because it will unfairly saddle consumers with unnecessary transmission costs that they *did not cause*. In addition, comments on Factor Category Seven identify several additional regulatory and practical obstacles that the final rule attempts to resolve by allowing transmission providers to dial the impact of these commitments and goals up or down.²⁶⁴ Further, this provision is yet another count in the final rule’s pattern of diminishing the states’ role in regional transmission planning by elevating mere *corporate preferences* to have equal if not greater stature as the policy choices of states and federally-recognized Tribes.

111. It is worth starting the examination of Factor Category Seven simply by pulling the curtain back and highlighting the coalitions of comments that the final rule cites supporting it and opposed to it.²⁶⁵ The strongest support for this provision comes from where we would all expect: the corporate interests with something to gain by shifting the costs that result from their preferential power purchase commitments to others along with the other special interests whose policy preferences have no place in developing a rate that is just and reasonable.²⁶⁶ I am similarly unsurprised that the skeptics and opponents of this provision are led by retail rate authorities, load-serving entities from coast to coast, and large multi-state RTOs. They understand that adopting Factor Category Seven is unfair, unworkable, and a mistake.

112. Factor Category Seven is as unlawful as it is unfair because it grossly violates cost causation principles of ratemaking.²⁶⁷ Whether a corporate commitment or a state/Tribal policy goal is directly attributed to increased transmission costs, the entities

²⁶³ *Id.* PP 481–484.

²⁶⁴ *Id.* P 484.

²⁶⁵ Commenters in favor include ACEG, AEE, Advanced Energy Buyers, Amazon, Breakthrough Energy, Center for Biological Diversity, Environmental Groups, Ørsted, PIOs, SEIA, and SREA. *Id.* PP 474–476. Commenters expressing qualified support include LADWP, MISO, and NRECA. *Id.* P 477. Commenters opposed include the Alabama Commission, California Commission, Duke, Illinois Commission, New York TOs, Pennsylvania Commission, PJM, and PPL. *Id.* PP 478–480.

²⁶⁶ See James Downing, *FERC Observers, Stakeholders Lay out What is at Stake with Tx Rule Looming*, RTO Insider, Apr. 22, 2024 (“State renewable portfolio standards are not driving as much of the need for new transmission as the corporate renewable energy buyers that [Clean Energy Buyers] represents are, [Clean Energy Buyers Senior Director Bryn Baker] added.”), <https://www.rtoinsider.com/76831-ferc-experts-what-at-stake-transmission-rule-looming/>.

²⁶⁷ For a reminder on the shell game and how it seeks to use the cost causation principle, see *supra* Sections I, III.A, IV.B.2.b.

²⁵² *Id.* P 1110.

²⁵³ *Id.*

²⁵⁴ *Id.* (footnote omitted).

²⁵⁵ *Id.* PP 1146–1148.

²⁵⁶ See *id.* P 1117.

²⁵⁷ *Id.*

²⁵⁸ *Id.*; see also *id.* P 1110.

with the self-imposed aspirations are the direct beneficiaries. Cost causation principles of ratemaking—not to mention reviewing courts—will dictate that those entities, and not any other transmission customer, are the beneficiaries of the resulting transmission built to accommodate the corporate commitments. As the direct beneficiaries, they will be responsible for the increased transmission costs driven by those commitments, goals, and preferences. Even worse, if one of these cost causers changes its commitment or goal, all of the transmission provider's customers could still be left paying for the increased costs that are *no longer attributable to any beneficiary*. This is not how a just or reasonable rate works.

113. Even if the unfair and unlawful Factor Category Seven is allowed to take effect, it will fail on its own terms for practical reasons. The final rule acknowledges that the corporate commitment or a state/Tribal policy goal are “more likely to change over the transmission planning horizon than factors in other required factor categories.”²⁶⁸ As a balm for this uncertainty, the final rule grants the transmission providers the discretion to apply the salve of a discount on the likelihood that any of these aspirations will come to pass. Nothing in the final rule will prevent transmission providers from discounting these commitments one hundred percent. This discount is simply an invitation for transmission providers to ignore Factor Category Seven.

114. Even worse, when a transmission provider expends its limited resources to read the tea leaves of corporate commitments and include them in the Long-Term Scenarios, that inclusion will result in a violation of the FPA. Applying the costs of one corporation's commitments to all of the transmission provider's customers amounts to undue discrimination against similarly situated customers *without* corporate commitments while bestowing an undue preference for those similarly situated customers *with* corporate commitments. Further, most utility customers are at a resource and access disadvantage to the deep-pocketed special interests (including the corporate commitments driven by their wealthy and sophisticated investor class) that enjoy influence and power. Rather than sticking the consumers with any part of the bill for the gold plating necessary for a different customer's corporate preferences, this Commission should not depart from its cost allocation precedent. Under that precedent, the beneficiaries are required to pay for the upgrades they are driving. This Commission should not now saddle less powerful people and small businesses with the costs of the choices made by influential corporations and their managers and investors.²⁶⁹

115. Let me be clear about how egregious and unfair this idea is with a hypothetical scenario. Suppose that a Fortune 500

company pressured by its investors commits to a corporate goal that it will only purchase electric power from certain preferred generation sources within a decade. It similarly commits to discriminate against power sourced from non-preferred generation resources. The transmission provider then informs the corporate customer that transmission upgrades will be necessary in order for those favored generation resources to actually deliver power to the corporate customer's facilities and to avoid receiving power from the non-preferred resources. Next, the transmission provider includes those upgrades in Factor Category Seven. Later, the transmission provider builds the necessary upgrades according to its regional transmission plan and incurs significant cost in doing so. Instead of attributing those costs to the corporate customer, the transmission provider socializes the upgrade costs to *all* of its customers. Rather than holding the actual cost causer accountable for the increase, the final rule instead dictates that the costs directly resulting from the customer's corporate commitment benefit *all* ratepayers because there are necessarily reliability and economic benefits that result from all transmission development. Then these increased costs are socialized across all of the transmission provider's customers. This realistic outcome is, to put it mildly, grossly unfair to consumers and a violation of the FPA.

116. Now suppose that a neighboring corporate customer (that receives an identical class of electric service as the customer in the prior hypothetical) announces in response its own corporate goal that it will never consider any factors other than reliability and cost in purchasing electric power because it wants to keep its costs as low as possible no matter what. How is a transmission provider supposed to accommodate that second corporate goal? Do the two commitments simply cancel each other out? Will the transmission provider carve out the second corporate customer? Where would that leave the customers who are silent with respect to these competing corporate goals? The final rule fails to answer these questions.

c. The Final Rule Walks Back the NOPR Proposal To Remove the CWIP Incentive

117. Today's final rule also walks back the widely supported proposal to remove the CWIP transmission incentive. As I have discussed above, it is apparent that the pretextual goal of this final rule is to get transmission built to serve political and corporate goals, no matter the cost and no matter who actually benefits from it.

118. As I noted on numerous occasions, a core principle of utility law and regulation for decades is that consumers can be forced to pay costs only for assets that are “used and useful” to them. In Order No. 679, the Commission determined that it may be necessary to depart from this long-standing ratemaking principle to “address the substantial challenges and risks in constructing new transmission.”²⁷⁰ And in

my prior statements, I questioned, among other concerns, whether the Commission's determination of whether “substantial challenges and risks” exist when granting the various transmission incentives has become nothing more than a check-the-box exercise.²⁷¹ In particular, I noted:

The Commission's incentive policies—particularly the CWIP Incentive, which allows recovery of costs *before* a project has been put into service—run the risk of making consumers “the bank” for the transmission developer; but, unlike a real bank, which gets to charge interest for the money it loans, under our existing incentives policies the consumer not only effectively “loans” the money through the formula rates mechanism, but also pays the utility a profit, known as Return on Equity, or “ROE,” for the privilege of serving as the utility's *de facto* lender.²⁷²

119. The proposal to remove the CWIP Incentive was a major reason why I supported the NOPR, despite its flaws, and a massive step in the right direction to remedy the harm to consumers that these incentives have caused over the years.²⁷³ However, instead of adopting the proposal to remove the CWIP Incentive, today's final rule chose to side with developers and special interest groups, rather than with consumers. Today's final rule rationalizes the decision to walk back the removal of the CWIP Incentive by finding that any action on the CWIP Incentive is more appropriately considered in a separate proceeding where incentives can be comprehensively evaluated for all regional transmission facilities.²⁷⁴ I regard that as nothing more than an excuse for a continuing failure to act.

120. Many commenters share my concerns that the CWIP Incentive inappropriately shifts risks to ratepayers and runs afoul of the core principle of utility law and regulation that consumers should pay costs only for assets that are “used and useful” to them.²⁷⁵ Others argue that removing the CWIP Incentive may mitigate the risk of

²⁷¹ See *supra* n.61.

²⁷² February 2022 Concurrence at P 3 (emphasis in original); July 2022 Concurrence at P 3 (citation omitted); see also NOPR Concurrence at P 15 (“CWIP is, of course, passed through as a cost to consumers, making consumers effectively an involuntary lender to the developer Consumers should be protected from paying CWIP costs during this potentially long period before a project actually enters service, if it ever does.”), <https://www.ferc.gov/news-events/news/commissioner-christies-concurrence-e-1-regional-transmission-planning-and-cost>.

²⁷³ See *supra* PP 18–19.

²⁷⁴ Final Rule, 187 FERC ¶ 61,068 at P 1547.

²⁷⁵ See, e.g., California Commission Reply Comments at 14; Kentucky Commission Chair Chandler Initial Comments at 4–9; NARUC Initial Comments at 55–56 (referencing PATH and that the Commission granted several transmission incentives, resulting in a 14.3% return on equity); NASUCA Initial Comments at 8–9; North Carolina Commission and Staff Initial Comments at 17–18; North Dakota Commission Initial Comments at 6; Ohio Commission Federal Advocate Initial Comments at 15–16; Ohio Consumers Initial Comments at 29–31; OMS Initial Comments at 14–15; Pennsylvania Commission Initial Comments at 17–18; PJM States Initial Comments at 13; Virginia Attorney General Reply Comments at 3–4.

²⁶⁸ Final Rule, 187 FERC ¶ 61,068 at P 484.

²⁶⁹ I also have grave concerns that the final rule tasks transmission planning engineers to try their hands at becoming Wall Street analysts when they attempt to guess how serious any of the corporate commitments really are.

²⁷⁰ *Promoting Transmission Inv. through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, at PP 26, 117, *order on reh'g*, Order No. 679–A, 117 FERC ¶ 61,345 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

overbuilding that may result from the other changes cemented in today's final rule.²⁷⁶ Today's final rule, however, is astoundingly silent on the consumer impact of retaining the CWIP Incentive.

121. Unfortunately, this is simply a continuation of the Commission punting on any meaningful reevaluation of transmission incentives. In my three years on the Commission, there has been *no* action to reevaluate the check-the-box award of transmission incentives, and it is far past time for me to begin dissenting from this lack of action on the Commission's part to change this shameful status quo.²⁷⁷ By walking back the removal of the CWIP Incentive, today's final rule reveals, one again, its failure to protect consumers as required by the FPA.

V. Conclusion

122. Had the states been given the authority to protect their consumers, as promised by the NOPR, I would have supported this rule just as I voted for the NOPR, as an imperfect but acceptable compromise.²⁷⁸ If transmission projects that are planned to implement public policies—the product of *political* decisions made by

politicians—or to implement corporate “green energy” power purchasing preferences—the product of corporate management and investors—are going to be included in long-term planning *mandated* by FERC, then the states must have the authority to consent to (i) the planning criteria (which determines which projects go into regional plans and receive cost recovery from consumers), *and* (ii) the formula for regional cost allocation of such projects.

123. This role for the states is not only essential but fair: fair to state policymakers and regulators and fair to the tens of millions of consumers they represent. The final rule, however, denies states that essential role and that denial renders this order unfair to the states and unfair to tens of millions of consumers.

124. As has been said before, denial is not just a river in Egypt. The short-sightedness of the final rule and the special interests who lobbied this Commission to deny states this key role is a denial of the reality of how transmission actually gets built in the union of states that is the United States of America. As a former state regulator who voted to approve scores of transmission projects, both regional and local, I will testify from experience that to get transmission built—especially the big, controversial regional lines of 500 kV and above—the states should not be dismissed as annoying obstacles that must be pushed out of the way by an omnipotent, omniscient FERC. Rather, state regulators must be respected as potential partners and, most importantly, *advocates* of such controversial lines, who will be invested in them and work to get them sited

and built within their borders. That will never happen if states are denied the role that I advocated in the NOPR, that of full partners in deciding how, when and whether their consumers are burdened with costs for politically and corporate-driven policy projects.

125. This final rule could have corrected the single biggest flaw in Order No. 1000: the exclusion of the states from decision-making roles in FERC-mandated regional transmission planning for public policy projects. Instead, the final rule doubles down on that error with a blizzard of new planning mandates to serve political, corporate, and ideological agendas, while leaving the states with no real power to protect their consumers from the trillions of dollars of costs that this order brazenly wants to impose on them. The final rule is nothing but a pretext for enacting a sweeping policy agenda that Congress never passed. As such, it blatantly violates the major questions doctrine. In producing rates that will be unjust, unreasonable, and unduly discriminatory and preferential, it violates the actual text of the FPA. And in that violation, it fails to fulfill our most important duty under the FPA, which is to protect consumers.

For these many reasons, I respectfully dissent.

Mark C. Christie
Commissioner

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²⁷⁶ See, e.g., Massachusetts Attorney General Initial Comments at 24–25; North Carolina Commission and Staff Initial Comments at 17–18; Pennsylvania Commission Initial Comments at 17–18; PJM States Initial Comments at 13.

²⁷⁷ See, e.g., *Baltimore Gas & Elec. Co.*, 187 FERC ¶ 61,030 (Christie, Comm'r, dissenting at P 6).

²⁷⁸ To reiterate what I said earlier: If I agree to get a root canal with anesthetic but learn upon arrival at the dentist's office that I still get the root canal but no anesthetic, that is not the original deal.



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Part III

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Public Company Accounting Oversight Board; Notice of Filing of Proposed Rules on a Firm's System of Quality Control and Related Amendments to PCAOB Standards; Notice

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–100277; File No. PCAOB–2024–02]

Public Company Accounting Oversight Board; Notice of Filing of Proposed Rules on a Firm's System of Quality Control and Related Amendments to PCAOB Standards

June 5, 2024.

Pursuant to section 107(b) of the Sarbanes-Oxley Act of 2002 (the “Act”), notice is hereby given that on May 24, 2024, the Public Company Accounting Oversight Board (the “Board” or the “PCAOB”) filed with the Securities and Exchange Commission (the “Commission”) the proposed rules described in items I and II below, which items have been prepared by the Board. The Commission is publishing this notice to solicit comments on the proposed rules from interested persons.

I. Board's Statement of the Terms of Substance of the Proposed Rules

On May 13, 2024, the Board adopted *A Firm's System of Quality Control and Other Amendments to PCAOB Standards, Rules, and Forms* (collectively, the “proposed rules”). The text of the proposed rules appears in Exhibit A to the SEC Filing Form 19b–4 and is available on the Board's website at Docket 046 | PCAOB (pcaobus.org) and at the Commission's Public Reference Room.

II. Board's Statement of the Purpose of, and Statutory Basis for, the Proposed Rules

In its filing with the Commission, the Board included statements concerning the purpose of, and basis for, the proposed rules and discussed any comments it received on the proposed rules. The text of these statements may be examined at the places specified in Item IV below. The Board has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements. In addition, the Board is requesting that the Commission approve the proposed rules, pursuant to section 103(a)(3)(C) of the Sarbanes-Oxley Act, for application to audits of emerging growth companies (“EGCs”), as that term is defined in section 3(a)(80) of the Securities Exchange Act of 1934 (“Exchange Act”). The Board's request is set forth in section D.

A. Board's Statement of the Purpose of, and Statutory Basis for, the Proposed Rules

(a) Purpose

The Board adopted a new PCAOB quality control (“QC”) standard that it believes will lead registered public accounting firms (“firms”) to significantly improve their QC systems. An effective QC system protects investors by facilitating the consistent preparation and issuance of informative, accurate, independent, and compliant engagement reports. Properly conducted audits and other engagements enhance the confidence of investors and other market participants in the information firms report on.

The Board adopted an integrated, risk-based standard, QC 1000, *A Firm's System of Quality Control*, that mandates quality objectives and key processes for all firms' QC systems, with a focus on accountability and continuous improvement. The Board has designed QC 1000 to be applied by firms of varying size and complexity. If approved by the U.S. Securities and Exchange Commission (the “SEC”), the Board believes this new standard will lead firms to better serve investors by more consistently complying with the professional and legal requirements that apply to PCAOB engagements.

In connection with the adoption of QC 1000, the Board also adopted other changes to its standards, rules, and forms. QC 1000 and the other changes adopted substantially reflect the Board's November 2022 proposal,¹ but have been modified in response to commenter input.

In a separate release, the Board also adopted a new auditing standard, AS 1000, *General Responsibilities of the Auditor in Conducting an Audit*, that addresses the general principles and responsibilities of the auditor.² This release includes references to AS 1000, where appropriate.

Improving the Board's QC Standards

The Board strongly believes that an effective quality control system facilitates continuous improvement. Over time, the PCAOB's oversight experience suggests that firm QC systems fall short. For example, PCAOB inspectors observed that approximately

40% of the issuer audits they reviewed in 2022 had one or more deficiencies where the auditor failed to obtain sufficient appropriate audit evidence to support its opinion, an increase of six percentage points over the deficiency rate in 2021 and 11 percentage points over the rate in 2020.³ In all those cases, auditors issued audit opinions without completing the audit work that PCAOB standards require for them to obtain reasonable assurance about whether the financial statements were free of material misstatement and/or whether the issuers maintained, in all material respects, effective internal control over financial reporting.

Every step of this rulemaking—from the December 2019 concept release,⁴ to the proposal, to adoption—has been informed by extensive research and outreach, as well as by PCAOB inspections and enforcement activities. The PCAOB's current QC standards were developed decades ago and issued by the American Institute of Certified Public Accountants (“AICPA”) before the PCAOB was established. The auditing environment has changed significantly since that time, including evolving and greater use of technology, and increasing auditor use of outside resources, such as other accounting firms and providers of support services. Firms themselves have also changed significantly, as has the role of firm networks. And advances in internal control, quality management, and enterprise risk management suggest that factors such as active involvement of leadership, focus on risk, clearly defined objectives, objective-oriented processes, monitoring, and remediation of identified issues can contribute to more effective QC. These developments have, in part, led to PCAOB advisory groups' general support for strengthening the QC standards, including through risk-based elements and enhanced requirements for firm governance and leadership.

Taking into account those considerations, as well as the comments the Board received on the concept release and proposal, the Board believes that improving PCAOB standards will lead firms to improve their QC systems. This should result in more consistent

³ See *Spotlight: Staff Update and Preview of 2022 Inspection Observations* (July 2023) (“2022 Inspection Observations Preview”), at 3, available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/documents/spotlight-staff-preview-2022-inspection-observations.pdf?sfvrsn=1b116d49_4.

⁴ See *Concept Release, Potential Approach to Revisions to PCAOB Quality Control Standards*, PCAOB Rel. No. 2019–003 (Dec. 17, 2019) (“concept release”), available on the Board's website in Docket 046.

¹ See *A Firm's System of Quality Control and Other Proposed Amendments to PCAOB Standards, Rules, and Forms*, PCAOB Rel. No. 2022–006 (Nov. 18, 2022) (“proposal” or “proposed standards”), available on the Board's website in Docket 046.

² See *General Responsibilities of the Auditor in Conducting an Audit and Amendments to PCAOB Standards*, PCAOB Rel. No. 2024–004 (May 13, 2024) (“Auditor Responsibilities Release”).

compliance with applicable requirements, which ultimately better serves and protects investors. The specific improvements the Board adopted include:

- Emphasizing accountability, firm culture and the “tone at the top,” and firm governance through requirements for specified roles within and responsibilities for the QC system, including at the highest levels of the firm; quality objectives that link compensation to quality; and, for the largest firms, the requirement of an independent perspective in firm governance;

- Striking the right balance between a risk-based approach to QC—which should drive firms to proactively identify and manage the specific risks associated with their practice—and a set of mandates, including required risk assessment and other QC-related processes, quality objectives, and quality responses—which should assure that the QC system is designed, implemented, and operated with an appropriate level of rigor;

- Addressing changes in the audit practice environment, including the increasing participation of other firms and other outside resources, the role of firm networks, the evolving use of technology and other resources, and the increasing importance of internal and external firm communications;

- Broadening responsibilities for monitoring and remediation of deficiencies to create a more effective ongoing feedback loop that drives continuous improvement; and

- Requiring a rigorous annual evaluation of the firm’s QC system and related reporting to the PCAOB, certified by key firm personnel, to underscore the importance of the annual evaluation of the QC system, reinforce individual accountability, and support PCAOB oversight.

Framework of the QC Standard

The Board carefully considered the characteristics of an appropriate framework for a PCAOB QC standard that could accomplish its regulatory goals. As a threshold issue, section 103 of the Sarbanes-Oxley Act of 2002 (“Sarbanes-Oxley”) provides that PCAOB QC standards must include requirements regarding certain specified matters, and also grants the Board broad authority to include such other requirements as it may prescribe in carrying out its investor protection mandate. The Board also considered how best to capture areas it had identified for improvement and how best to foster consistent, compliant implementation by the firms it

regulates. Because the Board believes it is the best structure for accomplishing its goals, the Board adopted the QC 1000 framework as proposed.

The Board notes that the framework has commonalities with other international and domestic standards for firm QC systems, though it goes beyond those requirements in a number of areas, including with regard to firm governance of the largest firms, more specific requirements for monitoring and remediation and the evaluation of the QC system, an ethics and independence component aligned with SEC and PCAOB requirements, and more specific provisions addressing technology and externally communicated firm-level and engagement-level information and metrics. The Board believes that building on a well-understood basic framework, appropriately tailored and strengthened to address its legal and regulatory environment and its investor protection mandate, will enable firms to implement and comply with QC 1000 more effectively. In designing, implementing, and operating their QC systems, firms that are subject to both PCAOB standards and other international or domestic QC standards—which the Board believes constitute a very substantial majority of the firms that perform engagements under PCAOB standards—can leverage the work they have already done and the investments they have already made to comply with those other requirements.

QC 1000

The Board developed QC 1000 with a view to its statutory mandate to protect the interests of investors and the public interest, and the Board believes the new standard will facilitate the consistent preparation and issuance of informative, accurate, and independent engagement reports. The final standard provides a framework for a QC system that is grounded in an ongoing process of proactively identifying and managing risks to quality, with a feedback loop from ongoing monitoring and remediation that should drive continuous improvement, an explicit focus on firm governance and leadership, firm culture, and individual accountability, and specific direction in a number of areas that current PCAOB standards do not address directly.

QC 1000 primarily consists of:

Two process components

- The firm’s risk assessment process
- The monitoring and remediation process

Six components that address aspects of the firm’s organization and operations

- Governance and leadership
 - Ethics and independence
 - Acceptance and continuance of engagements
 - Engagement performance
 - Resources
 - Information and communication
- Requirements for evaluation of and reporting on the QC system
- Annual evaluation of the effectiveness of the QC system
 - Reporting to the PCAOB on the QC system evaluation

The standard also includes requirements regarding individual roles and responsibilities in the QC system and documentation requirements.

Scalability

In the Board’s view, the basic objectives of the QC system should be the same for all firms, but the scope of the QC standard and how it applies should take into account the wide disparities in nature and circumstances across registered firms, in particular the extent to which their practices include engagements required to be performed under PCAOB standards and the complexity of such engagements. The risks that firms face, and therefore the specific policies and procedures necessary to appropriately serve investor interests through an effective QC system, vary significantly from the largest firms, operating as part of global networks, to local firms or sole proprietorships. QC 1000 establishes a uniform basic structure to be used by all firms, within which firms will be required to pursue an approach to quality control that is appropriate in light of the risks associated with their particular PCAOB audit practice. Aspects of the new standard are risk-based, and to that extent inherently scalable. In addition, it imposes more stringent requirements for the largest firms in some areas, while enabling smaller firms to comply with the core requirements in ways that take into account these firms’ size and the complexity of audits performed by them.

Scalability: Larger PCAOB Audit Practice

The Board believes that firms with a particularly extensive PCAOB audit practice (*i.e.*, those that issue audit reports for more than 100 issuers per year) should be subject to enhanced requirements, given such firms’ greater complexity and the relatively greater public interest implicated by the fact that they audit companies that make up

a substantial majority of U.S. public market capitalization. The incremental requirements under QC 1000 for such firms include:

- An external oversight function for the QC system compose of one or more persons who can exercise independent judgment related to the QC system;
- A program for collecting and addressing complaints and allegations that includes confidentiality protections;
- An automated system to track investments that may bear on independence; and
- Required monitoring of in-process engagements.

Scalability: Smaller PCAOB Audit Practice

Many firms perform only a small number of PCAOB engagements per year and are subject to resource constraints that larger PCAOB audit practices do not face. The Board has addressed the particular needs of these firms in a number of ways, including:

- Providing that a single individual may be assigned more than one of the QC system oversight roles required under the standard; and
- Allowing firms that issue five or fewer engagement reports for issuers or broker-dealers in a year to include audits not performed under PCAOB auditing standards in some of their monitoring activities.

Scalability: Firms That Do Not Have Responsibilities in Relation to a PCAOB Engagement

All registered firms will be required to design a QC system that meets the requirements of QC 1000. Firms will be required to implement and operate the QC system in compliance with QC 1000 when they lead an engagement under PCAOB standards, play a substantial role in the preparation or furnishing of an audit report (as defined in PCAOB rules), or have current responsibilities under applicable professional and legal requirements regarding any such engagement. This approach reflects the Board's view that all firms that register with the PCAOB should be appropriately prepared to perform a PCAOB engagement, regardless of whether they are currently subject to requirements with respect to one, while limiting the costs of compliance in circumstances where the risk to investor protection is minimal.

Key Changes From the QC 1000 Proposal

Key changes from the proposal include:

- For the firms with larger PCAOB audit practices, the requirement to include an independent oversight function for their QC system has been refined. Under the final rule, the external quality control function ("EQCF") will be composed of one or more persons who are not principals or employees of the firm and do not otherwise have a relationship with the firm that would interfere with the exercise of independent judgment with regard to matters related to the QC system. The responsibilities of the EQCF may vary across firms but include, at a minimum, evaluating the significant judgments made and the related conclusions reached by the firm when evaluating and reporting on the effectiveness of its QC system.

- The final rule requires firms to report on their QC system evaluation to the PCAOB, but not to the audit committee, as proposed. Legal constraints limit our ability to require public disclosures about the effectiveness of firms' QC systems at the level that some investors have requested. While the final rule recognizes the impediments to requiring public disclosure of QC system evaluation, the Board remains committed to finding additional ways of providing public disclosure to better inform investors about firms and PCAOB audit engagements. To that end, we have separately proposed a set of firm-level and engagement-level metrics across 11 areas that would be reported publicly.

- The timing of the QC system evaluation and reporting has changed. Under the final rule, the evaluation date for the annual evaluation of the QC system is September 30, rather than November 30 as proposed, with Form QC due by November 30 rather than January 15 of the following year. This shift allows more time between the evaluation date and the filing date than we proposed, but still allows sufficient time to generally enable the firm's monitoring activities to identify deficiencies in calendar year-end engagements and the results of that monitoring to be included in the evaluation.

Other Changes to PCAOB Standards, Rules, and Forms

In connection with the adoption of QC 1000, the Board also adopted other changes to PCAOB standards, rules, and forms. These include, among other changes, expanding the auditor's responsibility to respond to deficiencies on completed engagements under an amended and retitled AS 2901, *Responding to Engagement Deficiencies*

After Issuance of the Auditor's Report, and related amendments to AT No. 1, *Examination Engagements Regarding Compliance Reports of Brokers and Dealers*, and AT No. 2, *Review Engagements Regarding Exemption Reports of Brokers and Dealers*; and replacing the existing standard ET 102, *Integrity and Objectivity*, with a new standard, EI 1000, *Integrity and Objectivity*, to better align PCAOB ethics requirements with the scope, approach, and terminology of QC 1000.

Effective Date

If approved by the SEC, the final standard and related amendments to auditing standards, rules, and forms will take effect on December 15, 2025, with the initial evaluation of the QC system to be performed as of September 30, 2026, and initial reporting to the PCAOB by November 30, 2026. Firms will be permitted to elect to comply with the requirements of QC 1000, except reporting to the PCAOB on the annual evaluation of the QC system, before the effective date, at any point after SEC approval of the final standard and related amendments.

(b) Statutory Basis

The statutory basis for the proposed rules is Title I of Sarbanes-Oxley.

B. Board's Statement on Burden on Competition

Not applicable. The Board's consideration of the economic impacts of the proposed rules is discussed in section D below.

C. Board's Statement on Comments on the Proposed Rules Received From Members, Participants or Others

The Board issued a concept release regarding potential changes to quality control standards for public comment in PCAOB Release No. 2019-003 (Dec. 17, 2019). The Board received 36 written comment letters on the concept release. The Board released the proposed rule amendment for public comment in PCAOB Release No. 2022-006 (Nov. 18, 2022). The Board received 43 written comment letters on its proposal. The Board has carefully considered all comments received. The Board's response to the comments it received and the changes made to the rules in response to the comments received are discussed below.

Background

This section presents background information on this rulemaking, including an overview of existing PCAOB QC requirements and current practice, a review of other developments

since the current QC requirements were adopted, a summary of relevant actions taken by other standard setters, a discussion of PCAOB research and outreach efforts related to QC, the December 2019 concept release and 2022 proposal, and a summary of the key areas the Board has identified for improvement of the QC standards.

Overview of Existing Requirements and Current Practice

1. Requirements of the Sarbanes-Oxley Act of 2002

Sarbanes-Oxley requires the Board to establish certain professional standards, including quality control standards, to be used by registered public accounting firms in the preparation and issuance of audit reports for issuers, brokers, and dealers.⁵ Furthermore, Sarbanes-Oxley requires the PCAOB's QC standards to address:

- Monitoring of professional ethics and independence from issuers, brokers, and dealers on behalf of which the firm issues audit reports;
- Consultation within the firm on accounting and auditing questions;
- Supervision of audit work;
- Hiring, professional development, and advancement of personnel;
- Acceptance and continuation of engagements;
- Internal inspection; and
- Such other requirements as the Board may prescribe.⁶

2. Current PCAOB QC Standards

Under current PCAOB standards, a QC system is a process to provide a firm with reasonable assurance that its personnel comply with applicable professional standards and the firm's standards of quality.⁷ The QC system encompasses the firm's organizational structure and the policies adopted and procedures established to provide that reasonable assurance.⁸

Current PCAOB QC standards were adopted on an interim, transitional basis in 2003 from QC standards originally

developed and issued by the AICPA.⁹ They include three general QC standards that apply to all firms.¹⁰ Beyond that, they also include certain requirements of membership in the AICPA's former SEC Practice Section ("SECPS"), which apply only to firms that were SECPS members immediately prior to the adoption of the PCAOB's interim QC standards. Below is an overview of the general QC standards and the SECPS member requirements.

a. General QC Standards

i. QC 20, System of Quality Control for a CPA Firm's Accounting and Auditing Practice

QC 20 provides that a firm should have a system of quality control that provides the firm with reasonable assurance that its personnel comply with applicable professional standards and the firm's standards of quality.¹¹ In the context of engagement performance, the system of quality control should also provide reasonable assurance that the work performed meets applicable regulatory requirements.¹²

The firm's quality control policies and procedures should address the following elements:

- Independence, integrity, and objectivity;
- Personnel management;
- Acceptance and continuance of clients and engagements;
- Engagement performance; and
- Monitoring.¹³

These elements of quality control are interrelated.¹⁴ Policies and procedures should be established to provide the firm with reasonable assurance with respect to each of these elements of QC. An appropriate individual or individuals in the firm should be assigned responsibility for the design and maintenance of the various quality control policies and procedures.¹⁵ These policies and procedures should be communicated in a manner that provides reasonable assurance that personnel will understand and comply.¹⁶ Additionally, documentation

should be prepared to demonstrate compliance with the firm's policies and procedures for the elements of quality control.¹⁷

ii. QC 30, Monitoring a CPA Firm's Accounting and Auditing Practice

QC 30 addresses how a firm should implement the monitoring element of quality control discussed in QC 20. Monitoring involves an ongoing consideration and evaluation of the following:

- The relevance and adequacy of the firm's policies and procedures;
- The appropriateness of the firm's guidance materials and any practice aids;
- The effectiveness of professional development activities; and
- Compliance with the firm's policies and procedures.¹⁸

Under QC 30, monitoring procedures should enable the firm to obtain reasonable assurance that its system of quality control is effective.¹⁹ A firm's monitoring procedures may include:

- Inspection procedures;
- Pre-issuance or post-issuance review of selected engagements;
- Analysis and assessment of:
 - New professional pronouncements;
 - Results of independence confirmations;
 - Continuing professional education ("CPE") and other professional development activities undertaken by firm personnel;
 - Decisions related to acceptance and continuance of client relationships and engagements;
 - Interviews of firm personnel;
 - Determination of any corrective actions to be taken and improvements to be made in the quality control system;
 - Communication to appropriate firm personnel of any weaknesses identified in the quality control system or in the level of understanding or compliance therewith; and
 - Follow-up by appropriate firm personnel to ensure that any necessary modifications are made to the quality control policies and procedures on a timely basis.²⁰

The nature and extent of monitoring procedures generally depends on the firm's size and the nature and complexity of the firm's practice.²¹ QC 30 provides that individuals in a small firm may perform monitoring procedures, including post-issuance review of engagement working papers, reports, and clients' financial

⁵ See sections 101(c)(2) and 103(a)(1) of Sarbanes-Oxley, 15 U.S.C. 7211(c)(2), 7213(a)(1). This release uses the terms "issuer," "broker," and "dealer" as defined in Sarbanes-Oxley. See section 2(a)(7) of Sarbanes-Oxley, 15 U.S.C. 7201(7) (defining "issuer"); Sections 110(3) and (4) of Sarbanes-Oxley, 15 U.S.C. 7220(3), (4) (defining "broker" and "dealer"); see also PCAOB Rules 1001(b)(iii), (d)(iii), (i)(iii) (defining "broker," "dealer," and "issuer," respectively). Entities that are brokers or dealers or both are sometimes referred to herein as "broker-dealers."

⁶ See section 103(a)(2)(B) of Sarbanes-Oxley, 15 U.S.C. 7213(a)(2)(B).

⁷ See paragraph .03 of QC 20, System of Quality Control for a CPA Firm's Accounting and Auditing Practice.

⁸ See QC 20.04.

⁹ See PCAOB Rule 3400T, Interim Quality Control Standards; see also Establishment of Interim Professional Auditing Standards, PCAOB Rel. No. 2003-006 (Apr. 18, 2003).

¹⁰ Under PCAOB Rule 3400T(a), all firms are required to comply with QC standards as described in "the AICPA's Auditing Standards Board's Statements on Quality Control Standards, as in existence on April 16, 2003 (AICPA Professional Standards, QC §§ 20-40 (AICPA 2002)), to the extent not superseded or amended by the Board."

¹¹ See QC 20.03.

¹² See QC 20.17.

¹³ See QC 20.07.

¹⁴ See QC 20.08.

¹⁵ See QC 20.22.

¹⁶ See QC 20.23.

¹⁷ See QC 20.25.

¹⁸ See QC 30.02.

¹⁹ See QC 30.03.

²⁰ See QC 30.03.

²¹ See, e.g., QC 30.05, .10, .11.

statements, with respect to their own compliance with the firm's QC policies and procedures, but only if such individuals are able to critically review their own performance, assess their own strengths and weaknesses, and maintain an attitude of continual improvement.²²

iii. QC 40, The Personnel Management Element of a Firm's System of Quality Control—Competencies Required by a Practitioner-in-Charge of an Attest Engagement

QC 40 addresses the personnel management element of the quality control system. Personnel management includes hiring, assigning personnel to engagements, professional development, and advancement activities. Policies and procedures should be established to provide the firm with reasonable assurance that:

- Those hired possess the appropriate characteristics to enable them to perform competently.

- Work is assigned to personnel having the degree of technical training and proficiency required in the circumstances. Personnel participate in general and industry-specific continuing professional education and other professional development activities that enable them to fulfill responsibilities assigned, and satisfy applicable professional education requirements of the AICPA, and regulatory agencies.

- Personnel selected for advancement have the qualifications necessary for fulfillment of the responsibilities they will be called on to assume.²³

A firm's policies and procedures related to personnel management should be designed to provide a firm with reasonable assurance that practitioners-in-charge of engagements (i.e., engagement partners) possess the kinds of competencies that are appropriate given the circumstances of the client engagement.²⁴ Competencies are the knowledge, skills, and abilities that enable an engagement partner to be qualified to perform an engagement.²⁵ Competencies may be gained in various ways, including through relevant industry, governmental, and academic positions.²⁶ A firm's policies and procedures should ordinarily address the following competencies for an engagement partner:

- Understanding of the role of a system of quality control and a code of professional conduct;
- Understanding of the service to be performed;

- Technical proficiency;
- Familiarity with the industry;
- Professional judgment; and
- Understanding the organization's information technology systems.²⁷

Under QC 40, these competencies are interrelated.²⁸ When establishing policies and procedures related to competencies needed by an engagement partner, a firm may need to consider the requirements of policies and procedures established for other elements of quality control.²⁹

b. SECPS Member Requirements

The SECPS was a division of the AICPA for U.S. firms that audited public companies, which established incremental quality control requirements for its members. The SECPS requirements originally applied to all U.S. firms that audited public companies under AICPA standards. The SECPS ceased to exist following the establishment of the PCAOB.

Under PCAOB rules, certain SECPS requirements still apply to firms that were members of the SECPS as of April 16, 2003.³⁰ Based on current registration data, the SECPS member requirements apply to 201 (approximately 12% of) PCAOB-registered firms, including 11 of the 14 annually inspected firms in 2023.

i. Section 1000.08(d)—Continuing Professional Education of Audit Firm Personnel

Section 1000.08(d) requires SECPS member firms to ensure that all professionals residing in the United States, both CPAs and non-CPAs, participate in at least 20 hours of qualifying CPE every year and at least 120 hours every three years.³¹ Professionals who devote at least 25% of their time to performing audit, review, or other attest engagements, or who have responsibility for supervision or review of such engagements, must obtain at least 40% of their CPE hours in subjects related to accounting and auditing.³²

²⁷ See QC 40.08.

²⁸ See QC 40.09.

²⁹ See QC 40.10.

³⁰ PCAOB Rule 3400T(b) requires certain firms to comply with QC standards as described in "the AICPA SEC Practice Section's Requirements of Membership (d), (l), (m), (n)(1) and (o), as in existence on April 16, 2003 (AICPA SEC Practice Section Manual 1000.08(d), (j), (m), (n)(1) and (o)), to the extent not superseded or amended by the Board." The note to Rule 3400T provides that those requirements "only apply to those registered public accounting firms that were members of the AICPA SEC Practice Section on April 16, 2003." One of the SECPS member requirements, concerning concurring partner review, was superseded in 2009 by the PCAOB's adoption of AS 1220, *Engagement Quality Review*.

³¹ See SECPS 1000.08(d).

³² See SECPS 1000.08(d).

Additional information on Section 1000.08(d)'s CPE requirements appears in SECPS Section 8000, *Continuing Professional Education Requirements Effective for Educational Years Beginning After May 31, 2002*.³³ That information is summarized into three categories: (1) record-keeping for each professional to ensure that each professional adheres to all CPE requirements; (2) adherence to standards for CPE program sponsors for each program sponsored by the member firm; and (3) compliance with additional CPE requirements of the SECPS.³⁴ Appendix A to Section 8000 includes the AICPA policies related to CPE.

ii. Section 1000.08(l)—Communication by Written Statement to All Professional Personnel of Firm Policies and Procedures on the Recommendation and Approval of Accounting Principles, Present and Potential Client Relationships, and the Types of Services Provided

Section 1000.08(l) requires SECPS member firms to communicate, through a written statement, to all professional firm personnel the broad principles that influence the firm's quality control and operating policies and procedures.³⁵ Periodic communication also must inform professional firm personnel that compliance with those principles is mandatory.³⁶

iii. Section 1000.08(m)—Notification of the Commission of Resignations and Dismissals From Audit Engagements for Commission Registrants

Section 1000.08(m) requires that, if an SECPS member firm has resigned, declined to stand for reelection, or been dismissed as the auditor of an SEC registrant and the registrant has not reported the change in auditors to the SEC in a timely filed Form 8-K, the member firm is to report that the client-auditor relationship has ceased directly, in writing, to the former SEC client and the SEC within five business days.³⁷

³³ See SECPS 1000.08(d) (referring, in a footnote, to Section 8000).

³⁴ See SECPS 8000.

³⁵ See SECPS 1000.08(l). Section 1000.08(l) includes a cross-reference to Appendix H SECPS Section 1000.42, *Illustrative Statement of Firm Philosophy*, which provides an illustration of such a statement.

³⁶ See *id.*

³⁷ See SECPS 1000.08(m). Section 1000.08(m) cross-references Appendix D SECPS Section 1000.38, *Revised Definition of an SEC Client*, which provides the definition of an SEC client, as well as Appendix I SECPS Section 1000.43, *Standard Form of Letter Confirming the Cessation of the Client-Auditor Relationship*, which provides a standard form of such report.

²² See QC 30.09, .10.

²³ See QC 40.02.

²⁴ See QC 40.03.

²⁵ See QC 40.04.

²⁶ See QC 40.05.

iv. Section 1000.08(n)—Audit Firm Obligations With Respect to the Policies and Procedures of Correspondent Firms and of Other Members of International Firms or International Associations of Firms

Section 1000.08(n) requires SECPS member firms that are members of, correspondents with, or similarly associated with international firms or international associations of firms to seek adoption of policies and procedures that are consistent with the objectives in Appendix K (SECPS Section 1000.45), *SECPS Member Firms With Foreign Associated Firms That Audit SEC Registrants*.³⁸

Appendix K was adopted with the intention of enhancing the quality of SEC filings by issuers whose financial statements are audited by foreign associated firms of SECPS member firms.³⁹ It requires SECPS member firms to seek adoption by their international organizations or individual foreign associated firms of certain policies and procedures, including:

- Procedures to be performed on certain SEC filings by a filing reviewer who is knowledgeable in applicable accounting and auditing standards, independence requirements, and SEC rules and regulations;
- Inspection procedures for a sample of audit engagements performed by foreign associated firms for issuer clients, to be performed by inspection reviewers who are knowledgeable in the same areas as filing reviewers; and
- Policies and procedures under which disagreements between the filing or inspection reviewer and the audit partner-in-charge should be resolved in accordance with the policy of the international organization or the filing or inspection reviewer's firm.⁴⁰

v. Section 1000.08(o)—Policies and Procedures To Comply With Independence Requirements

Section 1000.08(o) requires SECPS member firms to have policies and procedures in place to comply with applicable independence requirements.⁴¹ Section 1000.08(o) cross-references Appendix L, SECPS Section 1000.46, *Independence Quality Controls*, which requires firms to establish written policies⁴² covering relationships with “restricted entities,”

for example, relationships between the restricted entity and the member firm, its benefit plans, and its professionals.⁴³ These relationships include investments, loans, brokerage accounts, business relationships, employment relationships, proscribed services, and fee arrangements.⁴⁴ Firms should maintain a database that includes all restricted entities (“restricted entity list”) and make the restricted entity list available to the firm’s professionals and to foreign associated firms.⁴⁵

A senior-level partner should be designated to oversee the independence policies and maintain and communicate the restricted entity list.⁴⁶ The policies and procedures also should require:

- Reviewing the restricted entity list prior to obtaining any security;
- Obtaining independence certifications from the firm’s professionals;
- Reporting violations of policies;
- Establishing a monitoring system; and
- Developing policies for potential sanctions for violations of the firm’s policies and procedures or professional independence requirements.⁴⁷

The policies and procedures should be made available to all professionals and a training program should be established to provide reasonable assurance that professionals understand the policies.⁴⁸

3. Observations From Oversight Activities

In the course of conducting inspections of registered public accounting firms⁴⁹ and investigating potential violations of PCAOB standards and other related laws and rules governing audits of public companies and audits and attestation engagements of broker-dealers, the PCAOB may identify deficiencies in firms’ execution of engagements and in firms’ QC systems. Oversight activities also help the PCAOB to identify good practices, both for engagements and for QC systems. The PCAOB also considers information derived from the SEC’s enforcement program.

Over time, firms have implemented a number of changes to their QC systems to remediate deficiencies identified through the PCAOB’s inspections

program.⁵⁰ Examples of changes firms have made in response to the Board’s inspections include:⁵¹

- *Independence*—Creating automated links between the firm’s tools for tracking subcontractors and evaluating and tracking business relationships to ensure that independence evaluations are complete and timely;

- *Engagement Performance*—Implementing new policies and procedures for engagement teams to focus on obtaining a thorough understanding of how issuers initiate, record, process, and report significant classes of transactions and how that information is recorded in the financial statements;

- *Resources*—Creating a committee to evaluate partner performance in relation to audit quality and establishing an accountability framework with penalties for negative audit quality events;

- *Monitoring and Remediation*—Adding new leadership positions to the internal inspection program, developing new analysis and reporting of internal inspection findings, and disseminating such findings more broadly; and

- *Monitoring and Remediation*—Adding in-process review and coaching programs to assist engagement teams in certain challenging areas, including internal control over financial reporting (“ICFR”) and accounting estimates.

Observations from PCAOB oversight activities have shown that improvements in quality controls can enhance the quality of engagements.⁵² However, PCAOB inspections continue to identify deficiencies related to engagements and the operation of firm QC systems, suggesting that not all firms have made meaningful improvements in these areas. Moreover, the pervasiveness of recent findings regarding such

⁵⁰ Additional information about the PCAOB remediation process is available on the PCAOB website at https://pcaobus.org/oversight/inspections/remediation/remediation_process.

⁵¹ Examples are drawn from firms’ Rule 4009 submissions. A Rule 4009 submission is a confidential submission prepared by a firm, pursuant to PCAOB Rule 4009, *Firm Response to Quality Control Defects*, concerning the ways in which a firm has addressed a QC criticism. For additional background, see *The Process for Board Determinations Regarding Firms’ Efforts to Address Quality Control Criticisms in Inspection Reports*, PCAOB Rel. No. 104–2006–077 (Mar. 21, 2006).

⁵² See, e.g., *Spotlight: Staff Update and Preview of 2021 Inspection Observations* (Dec. 2022) (“2021 Inspection Observations Preview”), at 20–22, available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/documents/staff-preview-2021-inspection-observations-spotlight.pdf?sfvrsn=d2590627_4;Staff%20Inspection%20Brief:Staff%20Preview%20of%202018%20Inspection%20Observations (May 6, 2019) (“2018 Inspection Observations Preview”), at 1–4, available at https://pcaob-assets.azureedge.net/pcaob-dev/docs/default-source/inspections/documents/staff-preview-2018-inspection-observations.pdf?sfvrsn=b5f8cb09_0.

³⁸ See SECPS 1000.08(n).

³⁹ See SECPS 1000.45.01.

⁴⁰ See *id.*

⁴¹ See SECPS 1000.08(o).

⁴² PCAOB rules do not mandate that writings be paper-based. See, e.g., paragraph .04 of AS 1215, *Audit Documentation* (audit documentation may be in the form of paper, electronic files, or other media).

⁴³ See SECPS 1000.46 (requirement 1).

⁴⁴ See *id.*

⁴⁵ See SECPS 1000.46 (requirements 4, 5, and 6).

⁴⁶ See SECPS 1000.46 (requirement 5).

⁴⁷ See SECPS 1000.46 (requirement 7).

⁴⁸ See SECPS 1000.46 (requirement 3).

⁴⁹ The information on inspections and remediation efforts is limited to those firms that are subject to inspection by the PCAOB.

deficiencies—both in terms of the number of firms affected and the percentage of deficient engagements—suggests that an updated QC standard is needed to drive proactive, systemic, and consistent improvements in audit quality rather than just case-by-case improvements in response to firm-specific findings.

The following discussion summarizes recent observations from PCAOB inspections⁵³ and investigations of QC systems, including deficiencies and violations—instances of noncompliance with PCAOB requirements—and good practices that the Board believes support and strengthen QC systems. The Board has taken these observations into account in developing the final QC standard and related amendments, rules, and forms.

a. QC Deficiencies and Violations Observed From Oversight Activities

PCAOB observations have generally revealed that while some firms have made improvements to their QC systems, the progress has been uneven. Even taking that progress into account, in roughly a third of the issuer audits the PCAOB inspected from 2020 to 2022, the auditor's opinion was not adequately supported.⁵⁴ This suggests that there is significant room for improvement in QC systems' ability to provide reasonable assurance that firm engagements are performed in accordance with applicable professional standards and regulatory requirements.

As described below, the PCAOB's observations all too frequently indicate that firms' QC systems did not appear to provide reasonable assurance that firm personnel will comply with applicable professional standards in, among others, the areas of: (1) acceptance of

engagements; (2) engagement performance; (3) independence, integrity, and objectivity; (4) personnel management; (5) monitoring; and (6) engagement quality reviews. Below are examples of the PCAOB's observations in these areas.

i. Acceptance of Engagements

A firm's QC system should provide the firm with reasonable assurance that it undertakes only those engagements that the firm can reasonably expect to be completed with professional competence.⁵⁵ This includes taking into consideration, among other things, the availability of resources to perform an engagement and the competence of those resources. The PCAOB has observed instances where a firm's lack of policies and procedures in the area of engagement acceptance and continuance resulted in accepting new engagements that were not completed with professional competence and resulted in numerous violations of PCAOB auditing standards.⁵⁶

ii. Engagement Performance

A properly functioning QC system should provide the firm with reasonable assurance that the work performed by engagement personnel meets applicable professional standards, regulatory requirements, and the firm's standards of quality.⁵⁷ A QC system cannot provide reasonable assurance if, for example, there are severe, frequent, or widespread deficiencies, or recurring instances of similar types of deficiencies at the engagement level. The PCAOB has observed deficiencies and violations in a range of areas of engagement performance, including, for example:

- Failure to identify and test controls that address risks of material misstatement or sufficiently evaluate review controls;
- Insufficient evaluation of significant assumptions or data used in developing an estimate;⁵⁸
- Unwarranted reliance on data or reports used in testing an issuer's

financial reporting controls or in substantive testing;⁵⁹

- Engagement partners' failure to adequately supervise the engagement with due professional care, which contributed to not identifying deficiencies;⁶⁰
- Failure to implement and maintain adequate policies and procedures to provide reasonable assurance that work is performed and documented;⁶¹ and
- Failure to ensure audits are performed under PCAOB standards and not another framework.⁶²

iii. Independence, Integrity, and Objectivity

A firm's QC system should also provide the firm with reasonable assurance that personnel maintain independence—in fact and in appearance—in all required circumstances.⁶³ Observations relating to auditor independence have been recurring over the last several years.⁶⁴

⁵⁹ See, e.g., *PKF O'Connor Davies, LLP*, PCAOB Rel. No. 105–2022–001.

⁶⁰ See, e.g., *Alfonse Gregory Giugliano, CPA*, SEC AAER No. 4458; *In the Matter of Deloitte Touche Tohmatsu Certified Public Accountants, LLP*, SEC AAER No. 4342 (Sept. 29, 2022); *In the Matter of RSM, SEC AAER No. 4346* (Sept. 30, 2022); *In the Matter of Mancera, S.C., Alejandro Valdez Mendoza, C.P., and Angel Rodames Corral Nieblas, C.P.*, SEC AAER No. 4198 (Dec. 17, 2020); *In the Matter of Whitley Penn LLP, Susan Lunn Powell, CPA, Jeffrey Shannon Lawlis, CPA, and John Griffin Babb, CPA*, PCAOB Rel. No. 105–2020–002 (Mar. 24, 2020); *In the Matter of David M. Burns, CPA*, PCAOB Rel. No. 105–2017–055 (Dec. 19, 2017); *In the Matter of BDO Auditores, S.L.P., Santiago Sañé Figueras, and José Ignacio Algas Fernández*, PCAOB Rel. No. 105–2017–039 (Sept. 26, 2017); *In the Matter of KPMG LLP and John Riordan, CPA*, SEC AAER No. 3888 (Aug. 15, 2017).

⁶¹ See, e.g., *WithumSmith+Brown, PC*, PCAOB Rel. No. 105–2024–010; *In the Matter of SW Audit*, PCAOB Rel. No. 105–2024–009 (Feb. 20, 2024); *Shama, PCAOB Rel. No. 105–2024–004*; *In the Matter of Haynie & Company*, PCAOB Rel. No. 105–2024–001 (Jan. 23, 2024); *Shandong Haoxin Certified Public Accountants Co., Ltd.*, PCAOB Rel. No. 105–2023–045; *In the Matter of Deloitte & Touche S.A.S.*, PCAOB Rel. No. 105–2023–025 (Sept. 26, 2023); *Marcum LLP*, SEC AAER No. 4423; *Deloitte Touche Tohmatsu Certified Public Accountants, LLP*, SEC AAER No. 4342; *In the Matter of HLB Mann Judd, Darryl Swindells, and Aidan Smith*, PCAOB Rel. No. 105–2020–008 (June 29, 2020); *In the Matter of Castillo Miranda y Compañía, S.C., Ignacio García Párreras, Juan Martín Gudiño Casillas, Luis Raúl Michel Domínguez, Juan Francisco Olvera Díaz, Carlos Rivas Ramos, and Bernardo Soto Peñañiel*, PCAOB Rel. No. 105–2019–028 (Oct. 31, 2019); *In the Matter of Deloitte Anjin LLC*, PCAOB Rel. No. 105–2019–025 (Oct. 31, 2019); *In the Matter of Deloitte Touche Tohmatsu Auditores Independientes*, PCAOB Rel. No. 105–2016–031 (Dec. 5, 2016).

⁶² See, e.g., *In the Matter of Dale Matheson Carr-Hilton LaBonte LLP*, PCAOB Rel. No. 105–2021–021 (Dec. 14, 2021); *In the Matter of WDM Chartered Professional Accountants and Mike Kao*, PCAOB Rel. No. 105–2021–016 (Sept. 30, 2021).

⁶³ See QC 20.09.

⁶⁴ See, e.g., 2022 Inspection Observations Preview at 18; 2021 Inspection Observations Preview at 19; PCAOB, *Spotlight: Staff Update and Preview of*

⁵³ PCAOB inspections are designed to assess a firm's compliance with PCAOB standards and rules and other applicable regulatory and professional requirements with respect to the firm's QC system and in the portions of engagements selected for review. An inspection does not involve a review of all aspects of a firm's QC system. An inspection also does not necessarily involve a review of all of a firm's engagements, nor is it designed to identify every deficiency in the reviewed engagements. The inspection data are derived from PCAOB inspection reports. Part II of PCAOB inspection reports include criticisms of, and potential defects in, a firm's QC system, to the extent any are identified. The PCAOB includes, in Part II of its inspection reports, deficiencies observed in inspections of individual engagements when the results indicate that the firm's QC system does not provide reasonable assurance that firm personnel will comply with applicable professional standards and regulatory requirements. In evaluating whether engagement observations are indicative of QC deficiencies, PCAOB staff consider the nature, significance, and frequency of deficiencies; related firm methodology, guidance, and practices; and possible root causes.

⁵⁴ See Figure 1 below, and accompanying text for an analysis of 2011–2022 inspections data.

⁵⁵ See QC 20.15.

⁵⁶ See, e.g., *In the Matter of WithumSmith+Brown, PC*, PCAOB Rel. No. 105–2024–010 (Feb. 20, 2024); *In the Matter of Jack Shama and Jack Shama, CPA*, PCAOB Rel. No. 105–2024–004 (Jan. 23, 2024); *In the Matter of Shandong Haoxin Certified Public Accountants Co., Ltd., LIU Kun, MA Yao, SUN Penghuan, and ZHU Dawei*, PCAOB Rel. No. 105–2023–045 (Nov. 30, 2023); *In the Matter of Alfonse Gregory Giugliano, CPA*, SEC Accounting and Auditing Enforcement Release (“AAER”) No. 4458 (Sept. 12, 2023); *In the Matter of Marcum LLP*, PCAOB Rel. No. 105–2023–005 (June 21, 2023); *In the Matter of Marcum LLP*, SEC AAER No. 4423 (June 21, 2023).

⁵⁷ See QC 20.17.

⁵⁸ See, e.g., *WithumSmith+Brown, PC*, PCAOB Rel. No. 105–2024–010.

Examples of these observations frequently have included:

- Violations of independence, including financial relationship and partner rotation requirements of 17 CFR 210.2–01;⁶⁵
- Noncompliance by firm personnel in reporting their financial relationships during the independence confirmation process;
- Independence violations related to the firm providing impermissible non-audit services;⁶⁶
- Noncompliance with PCAOB Rule 3524, *Audit Committee Pre-approval of Certain Tax Services*, and PCAOB Rule 3526, *Communication with Audit Committees Concerning Independence*;⁶⁷
- Improper inclusion of indemnification clauses in engagement letters, which impaired independence based on the general standard of independence prescribed by 17 CFR 210.2–01(b); and
- Failure to implement and maintain adequate policies and procedures to provide reasonable assurance that firm personnel timely consult on complex, unusual, or unfamiliar independence issues.⁶⁸

The PCAOB has also observed highly concerning, widespread instances where firm personnel have improperly shared answers on examinations required to

2020 Inspection Observations (Oct. 2021) (“2020 Inspection Observations Preview”), at 12, available at https://pcaob-assets.azureedge.net/pcaob-dev/docs/default-source/inspections/documents/inspections-outlook-for-2019.pdf?sfvrsn=538b8bb7_2.

⁶⁵ See, e.g., *In the Matter of Ernst & Young LLP*, James G. Herring, Jr., CPA, James A. Young, CPA, and Curt W. Fochtmann, CPA, SEC AAER No. 4239 (Aug. 2, 2021); *In the Matter of Raich Ende Malter & Co.*, PCAOB Rel. No. 105–2019–009 (Apr. 9, 2019); *In the Matter of Marcum LLP and Alfonso Gregory Giugliano, CPA*, PCAOB Rel. No. 105–2019–022 (Sept. 10, 2019); *In the Matter of Marcum Bernstein & Pinchuk LLP*, PCAOB Rel. No. 105–2019–023 (Sept. 10, 2019).

⁶⁶ See, e.g., *In the Matter of Pricewaterhousecoopers LLP*, SEC AAER No. 4084 (Sept. 23, 2019); *In the Matter of RSM US LLP (f/k/a McGladrey LLP)*, SEC AAER No. 4066 (Aug. 27, 2019).

⁶⁷ See, e.g., *In the Matter of PricewaterhouseCoopers, S.C.*, PCAOB Rel. No. 105–2019–017 (Aug. 1, 2019); *In the Matter of BDO Magyarorszag Konyvvizsgalo Kft.*, PCAOB Rel. No. 105–2017–024 (Apr. 12, 2017).

⁶⁸ See, e.g., *In the Matter of PricewaterhouseCoopers LLP*, PCAOB Rel. No. 105–2024–014 (Mar. 28, 2024).

obtain or maintain professional licenses.⁶⁹ The Board has acted decisively in responding to this conduct, which was prevalent both domestically and internationally.⁷⁰ The PCAOB has also observed instances where firm personnel have not acted with integrity by altering work papers⁷¹ or failing to cooperate with the Board.⁷²

These recurring deficiencies and violations suggest that some firms and their personnel either do not have the requisite understanding of applicable independence and ethics requirements, or, as evidenced by the systemic nature of certain of these violations, do not have appropriate controls in place to prevent violations.⁷³

iv. Personnel Management

The quality of a firm’s work ultimately depends on the integrity, objectivity, intelligence, competence, experience, and motivation of personnel who perform, supervise, and review the work.⁷⁴ A firm’s QC system should provide the firm with reasonable

⁶⁹ See, e.g., *In the Matter of Navarro Amper & Co.*, PCAOB Rel. No. 105–2024–025 (Apr. 10, 2024); *In the Matter of Imelda & Rekan*, PCAOB Rel. No. 105–2024–024 (Apr. 10, 2024); *In the Matter of KPMG Accountants N.V.*, PCAOB Rel. No. 105–2024–022 (Apr. 10, 2024); *In the Matter of KPMG LLP (United Kingdom)*, PCAOB Rel. No. 105–2022–032 (Dec. 6, 2022); *In the Matter of Ernst & Young LLP, SEC AAER No. 4313 (June 28, 2022)*; *In the Matter of PricewaterhouseCoopers LLP*, PCAOB Rel. No. 105–2022–002 (Feb. 24, 2022); *In the Matter of KPMG*, PCAOB Rel. No. 105–2021–008 (Sept. 13, 2021); *In the Matter of KPMG LLP, SEC AAER No. 4051 (June 17, 2019)*.

⁷⁰ See, e.g., *In the Matter of PricewaterhouseCoopers Zhong Tian LLP*, PCAOB Rel. No. 105–2023–044 (Nov. 30, 2023); *In the Matter of PricewaterhouseCoopers*, PCAOB Rel. No. 105–2023–043 (Nov. 30, 2023); *KPMG LLP (United Kingdom)*, PCAOB Rel. No. 105–2022–032 (Dec. 6, 2022); *PricewaterhouseCoopers LLP*, PCAOB Rel. No. 105–2022–002 (Feb. 24, 2022); *KPMG*, PCAOB Rel. No. 105–2021–008 (Sept. 13, 2021).

⁷¹ See, e.g., *In the Matter of Jose Daniel Melendez Gimenez*, PCAOB Rel. No. 105–2022–035 (Dec. 6, 2022); *In the Matter of Edgar Mauricio Ramirez Rueda*, PCAOB Rel. No. 105–2022–036 (Dec. 6, 2022); *In the Matter of Marco Alexander Rodriguez Ramirez*, PCAOB Rel. No. 105–2022–037 (Dec. 6, 2022); *In the Matter of KPMG S.A.S.*, PCAOB Rel. No. 105–2022–034 (Dec. 6, 2022); *In the Matter of Jonathan B. Taylor, CPA*, PCAOB Rel. No. 105–2022–025 (Oct. 18, 2022); *Castillo Miranda y Compania, S.C.*, PCAOB Rel. No. 105–2019–028 (Dec. 6, 2022); *Deloitte Anjin LLC*, PCAOB Rel. No. 105–2019–025 (Dec. 6, 2022); *Deloitte Touche Tohmatsu Auditores Independientes*, PCAOB Rel. No. 105–2016–031 (Dec. 6, 2022).

⁷² See, e.g., *Shandong Haoxin Certified Public Accountants Co., Ltd.*, PCAOB Rel. No. 105–2023–045 (Dec. 6, 2022); *Jose Daniel Melendez Gimenez*, PCAOB Rel. No. 105–2022–035 (Dec. 6, 2022); *Edgar Mauricio Ramirez Rueda*, PCAOB Rel. No. 105–2022–036 (Dec. 6, 2022); *Marco Alexander Rodriguez Ramirez*, PCAOB Rel. No. 105–2022–037 (Dec. 6, 2022); *Jose Daniel Melendez Gimenez*, PCAOB Rel. No. 105–2022–035 (Dec. 6, 2022); *Castillo Miranda y Compania, S.C.*, PCAOB Rel. No. 105–2019–028 (Dec. 6, 2022); *Deloitte Touche Tohmatsu Auditores Independientes*, PCAOB Rel. No. 105–2016–031 (Dec. 6, 2022).

⁷³ See 2021 Inspection Observations Preview at 19; 2019 Inspections Outlook at 2.

⁷⁴ See QC 20.12.

assurance that personnel participate in general and industry-specific CPE and other professional development activities that enable them to fulfill responsibilities assigned and satisfy applicable CPE requirements.⁷⁵ A firm’s QC system also should provide the firm with reasonable assurance that personnel possess the appropriate characteristics to enable them to perform competently and that work is assigned to personnel having the degree of technical training and proficiency required in the circumstances.⁷⁶

The PCAOB has observed deficiencies related to compliance with the firm’s auditing policies and procedures.⁷⁷ The PCAOB also has observed deficiencies and violations where the firm did not assign personnel to engagements who had the training and proficiency required to perform audit work in accordance with PCAOB standards.⁷⁸

v. Monitoring

A firm’s QC system should provide the firm with reasonable assurance that its policies and procedures are suitably designed and effectively applied.⁷⁹ The PCAOB has observed situations where a firm’s internal inspection procedures did not detect significant audit deficiencies or the firm did not make changes to address repeated identified audit deficiencies.⁸⁰ These deficiencies and violations were subsequently identified through SEC and PCAOB oversight.⁸¹

⁷⁵ See QC 20.13c.

⁷⁶ See QC 20.13a. and b.

⁷⁷ See 2022 Inspection Observations Preview at 18.

⁷⁸ See, e.g., *Jack Shama*, PCAOB Rel. No. 105–2024–004; *In the Matter of Hall & Company Certified Public Accountants & Consultants, Inc.*, and *Anthony J. Price, CPA*, PCAOB Rel. No. 105–2022–029 (Nov. 3, 2022); *In the Matter of PKF O’Connor Davies, LLP*, PCAOB Rel. No. 105–2022–001 (Jan. 25, 2022); *In the Matter of WDM Chartered Professional Accountants*, PCAOB Rel. No. 105–2021–016 (Sept. 30, 2021); *In the Matter of Grant Thornton LLP*, PCAOB Rel. No. 105–2017–054 (Dec. 19, 2017); *BDO Auditores, S.L.P.*, *Santiago Sañé Figueras*, and *José Ignacio Algas Fernández*, PCAOB Rel. No. 105–2017–039.

⁷⁹ See QC 20.20.

⁸⁰ See, e.g., 2022 Inspection Observations Preview at 19.

⁸¹ See, e.g., *In the Matter of KPMG Assurance and Consulting Services LLP and Sagar Pravin Lakhani*, PCAOB Rel. No. 105–2022–033 (Dec. 6, 2022); *In the Matter of Friedman LLP*, SEC AAER No. 4339 (Sept. 23, 2022); *In the Matter of BMKR LLP and Joseph Mortimer, CPA*, PCAOB Rel. No. 105–2022–003 (Feb. 24, 2022); *PKF O’Connor Davies, LLP*, PCAOB Rel. No. 105–2022–001 (Jan. 25, 2022); *WDM Chartered Professional Accountants*, PCAOB Rel. No. 105–2021–016; *In the Matter of Haskell & White LLP*, PCAOB Rel. No. 105–2021–006 (Aug. 13, 2021); *In the Matter of RBMS LLP*, PCAOB Rel. No. 105–2021–004 (Aug. 9, 2021); *Castillo Miranda y Compania, S.C.*, PCAOB Rel. No. 105–2019–028 (Dec. 6, 2022); *Marcum LLP*, PCAOB Rel. No. 105–2019–022 (Dec. 6, 2022).

Continued

vi. Engagement Quality Reviews

Both the PCAOB and SEC have identified deficiencies and violations in audit areas that require evaluation by the engagement quality reviewer ("EQR").⁸² which suggests the EQR did not perform the evaluation with due professional care.⁸³ Additionally, for certain broker-dealer audit and attestation engagements, the PCAOB has observed instances where engagement quality reviews were not performed or sufficiently documented⁸⁴ and policies and procedures did not provide reasonable assurance that engagement quality reviews were performed with due professional care.⁸⁵

b. Good Practices Observed From Inspections

The following observations regarding good QC practices are based on inspections in recent years.⁸⁶ A good QC practice could be a procedure, technique, or methodology that is

Marcum Bernstein & Pinchuk LLP, PCAOB Rel. No. 105–2019–023 PricewaterhouseCoopers, S.C., PCAOB Rel. No. 105–2019–017; In the Matter of Bharat Parikh & Associates Chartered Accountants, Bharatkumar Balmukund Parikh, FCA, and Anuj Bharatkumar Parikh, PCAOB Rel. No. 105–2019–003 (Mar. 19, 2019); Grant Thornton, PCAOB Rel. No. 105–2017–054.

⁸² See, e.g., *Spotlight: Inspection Observations Related to Engagement Quality Reviews* (Oct. 2023), available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/documents/eqr-spotlight.pdf?sfvrsn=95a345e6_4; 2022 Inspection Observations Preview at 19; 2021 Inspection Observations Preview at 20; 2018 Inspection Observations Preview, at 4; 2020 Inspection Observations Preview at 12.

⁸³ See, e.g., In the Matter of RAM Associates & Company LLC and Parameswara K. Ramachandran, PCAOB Rel. No. 105–2023–021 (Aug. 8, 2023); In the Matter of Total Asia Associates PLT, PCAOB Rel. No. 105–2023–007 (June 23, 2023); In the Matter of RT LLP, PCAOB Rel. No. 105–2023–002 (Apr. 11, 2023); In the Matter of Donald R. Burke, CPA, PCAOB Rel. No. 105–2021–012 (Sept. 29, 2021); RBMS LLP, PCAOB Rel. No. 105–2021–00; In the Matter of Cheryl L. Gore, CPA and Stanley R. Langston, CPA, PCAOB Rel. No. 105–2021–020 (Dec. 14, 2021); Whitley Penn LLP, PCAOB Rel. No. 105–2020–002; In the Matter of Helen R. Liao, CPA, PCAOB Rel. No. 105–2020–014 (Sept. 24, 2020); In the Matter of Crowe Horwath LLP, Joseph C. Macina, CPA, and Kevin V. Wydra, CPA, SEC AAER No. 4007 (Dec. 21, 2018); In the Matter of BDO Auditores, S.L.P., PCAOB Rel. No. 105–2017–039.

⁸⁴ See, e.g., In the Matter of Alvarez & Associates, Inc., Certified Public Accountants, and Vicente Alvarez, CPA, PCAOB Rel. No. 105–2022–039 (Dec. 21, 2022); In the Matter of Citrin Cooperman & Company, LLP, Joseph Puglisi, CPA, Mark Schniebolk, CPA, and John Cavallone, CPA, PCAOB Rel. No. 105–2022–007 (May 11, 2022).

⁸⁵ See *Annual Report on the Interim Inspection Program Related to Audits of Brokers and Dealers*, PCAOB Rel. No. 2023–005 (Aug. 10, 2023) ("2022 Broker-Dealer Inspection Report"), at 31.

⁸⁶ See, e.g., 2022 Inspection Observations Preview; 2021 Inspection Observations Preview; 2020 Inspection Observations Preview; 2019 Inspection Observations Preview; and 2018 Inspection Observations Preview.

appropriately comprehensive and suitably designed in relation to a firm's size and the nature and complexity of the firm's practice. The Board has taken these observations into account in its consideration of QC 1000, while recognizing that the nature, extent, and formality of the design, implementation, and operation of QC systems can vary across firms.

i. Well-Defined QC System

A well-defined QC system includes all key elements of quality control and is supported by documentation that helps to promote firm personnel's understanding and consistent application of the firm's QC system. Helpful characteristics that the PCAOB has observed in some firms' QC systems include:

- Narratives and process flows that articulate how and where quality objectives fit within the QC processes and define risks posed to those quality objectives, including considering what could go wrong along the way;⁸⁷ and
- Developing risk and control matrices that include well-defined controls.

ii. Accountability for Audit Quality

Leadership involvement in and commitment to a firm's QC system sets the tone at the top and drives clear expectations regarding the importance of audit quality. The PCAOB observed positive behaviors where firms have placed an emphasis on the importance of audit quality through extending accountability beyond engagement partners to other key leaders at the firm, such as audit quality leaders, technical experts, and office leaders, through performance management processes.⁸⁸

iii. Root Cause Analysis of Identified Deficiencies

Identifying causal factors for engagement and QC deficiencies (*i.e.*, root cause analysis) can enable a firm to determine the appropriate response to and remediation of deficiencies and modify policies and procedures to prevent similar occurrences in the future. The PCAOB has observed that thorough root cause analyses drive better remediation of identified deficiencies. If root cause analysis is performed by a centralized team, having a defined process to share data and lessons learned outside of the root cause analysis team may further enhance the performance of a firm's QC system.

Through its inspection activities the PCAOB has observed that some firms'

root cause analysis programs have significantly evolved since the PCAOB was formed. The PCAOB has observed that some firms' approach to root cause analysis includes one or more of the following:

- Interviews with engagement teams and firm leadership;
- Use of proprietary tools to analyze large amounts of data;
- Root cause analysis training and the use of templates to facilitate consistency;
- Consideration of available performance metrics, such as engagement hours, training records, audit milestone dates, and partner experience years; and
- Consideration of positive quality events (*i.e.*, actions, behaviors, or conditions that resulted in positive outcomes, such as where aspects of the firm's QC system operated effectively or where no engagement deficiencies were identified for individual engagements) to identify whether such actions, behaviors, or conditions were present on engagements where QC deficiencies were identified.

iv. Timely Monitoring and Evaluation Activities

Timely and effective monitoring activities drive high-quality audits. The PCAOB has observed several good practices followed by some firms in their monitoring activities, including:

- Increased real-time monitoring of in-process audit engagements, for example, through pre-issuance reviews or coaching programs;⁸⁹
- Formalized monitoring processes and actions for defined triggering events, including restatements, internal and external inspection results, and results of peer reviews; and
- Mature QC processes including internal self-certifications of the effectiveness of QC components and sub-components.

Other Developments Since the Adoption of Current PCAOB QC Standards

Since the PCAOB's current QC standards were first developed and issued, the auditing environment has changed significantly. The current QC standards were developed in the context of the self-regulatory peer-review system that existed before the establishment of the PCAOB. Therefore, they were not written with a view to inspection and enforcement by a regulator and do not address the current regulatory environment, including firms' responsibilities with respect to

⁸⁷ See 2021 Inspection Observations Preview at 22; 2019 Inspection Observations Preview at 4.

⁸⁸ See 2018 Inspection Observations Preview at 2.

⁸⁹ See 2020 Inspection Observations Preview at 4, 13.

information brought to their attention through the PCAOB inspection process.

Since the QC standards were established, there have been significant developments in the availability and use of technologies and data analytic techniques, the organizational structure and management of firms have changed, and some firms have significantly increased their focus on governance and quality control.

For example, there have been significant developments in the use of technology by firms in relation to QC activities and performing engagements. Some firms have made significant investments in internally developed tools for use in the audit. The increased availability of “off-the-shelf” technologies, such as analytical software packages, has made some tools more readily available for use by firms. Firms developing or acquiring new technology-based tools, making changes to existing tools, and training firm personnel on how and when to use such tools have had impacts on QC. Many of these tools may reduce risk, for example by reducing the possibility of human error and enabling the analysis of whole populations of transactions rather than samples. But they may also create new risks if they do not work as intended or are used incorrectly.

Furthermore, some firm management and organizational structures have evolved to include more focus on centralization and a globally consistent methodology. Some firms have increased their use of services and resources supplied by firm networks, affiliates, and third-party providers. For example, some global networks are increasingly imposing requirements on member firms regarding the use of methodologies, technology, and policies and procedures that are developed or established at the network level. Some firms have also increased their use of shared service centers to assist with QC activities or performing engagements. In addition, some firms have changed their governance structures either voluntarily or due to changes in legal requirements.⁹⁰ At the same time, some firms have begun to publish “transparency reports” that seek to inform the public about the firm’s operations and quality control systems and practices.

Additionally, some firms have strengthened their approaches to firm governance and leadership, incentive systems, culture, and accountability. For example, some firms have added external parties to oversight roles. Some firms have also augmented their monitoring and remediation processes, including through implementing or enhancing ongoing monitoring activities and internal inspection processes, establishing processes for considering PCAOB inspection findings, performing root cause analysis, and increasing remediation efforts. Observations from PCAOB oversight activities have shown that improvements in quality controls can enhance the quality of audits.⁹¹ However, as noted above, PCAOB oversight activities continue to identify pervasive deficiencies, suggesting that many firms have meaningful improvements to make.

There have also been notable advances in internal control, quality management, and enterprise risk management frameworks and approaches, including the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) framework for internal control⁹² and the International Organization for Standardization (“ISO”) quality control standard ISO 9000:2015.⁹³ Many of these share important commonalities, stressing active involvement of leadership, focus on risk, clearly defined objectives, objective-oriented processes, monitoring, and remediation of identified issues. Academic research suggests that these frameworks improve company performance.⁹⁴

Actions by Other Standard Setters

Following is a brief description of the quality control standards adopted by the IAASB and the AICPA.

1. IAASB

The IAASB identified concerns related to its then effective QC standard, International Standard on Quality Control (ISQC) 1, *Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance and Related Services Engagements*, and decided to take steps to improve the standard. In December 2020, the IAASB released a suite of new

quality management standards, including International Standard on Quality Management 1, *Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements* (“ISQM 1”),⁹⁵ which became effective on December 15, 2022.⁹⁶

2. AICPA

In May 2022, the Auditing Standards Board of the AICPA adopted new quality management standards designed to improve a firm’s risk assessment and audit quality, including Statement on Quality Management Standards (SQMS) No. 1, *A Firm’s System of Quality Management* (“SQMS 1”).⁹⁷ The AICPA’s quality management standards closely align with the IAASB’s quality management standards, adapted for private companies in the United States. The new AICPA standards will become effective on December 15, 2025.

PCAOB Outreach and Research

The Board and its advisory groups have long considered the potential for improvements to PCAOB QC standards. For example, in 2010, the Standing Advisory Group (“SAG”) discussed a potential QC rulemaking project, including considerations and potential challenges in designing and implementing a QC system.⁹⁸ In 2014,

⁹⁵ In addition to ISQM 1, the IAASB adopted two other standards, International Standard on Quality Management 2, *Engagement Quality Reviews* (“ISQM 2”), and International Standard on Auditing 220 (Revised), *Quality Management for an Audit of Financial Statements* (“ISA 220 (Revised)”). ISQM 2 operates at the firm level, and is analogous to PCAOB AS 1220, *Engagement Quality Review*. ISA 220 (Revised) operates at the engagement level and deals with the engagement partner’s and the engagement team’s responsibilities for quality management for an audit of financial statements. Similar topics are addressed in PCAOB standards in AS 1201, *Supervision of the Audit Engagement*.

⁹⁶ ISQM 1 sets forth eight components of a QC system that operate in an iterative and integrated manner, as well as other requirements. See IAASB Fact Sheet, *Introduction to ISQM 1, Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements* (Dec. 2020), available at <https://www.ifac.org/system/files/publications/files/IAASB-ISQM-1-Fact-Sheet.pdf>.

⁹⁷ The AICPA’s other QC standards are SQMS No. 2, *Engagement Quality Reviews*; Statement on Auditing Standards (SAS) No. 146, *Quality Management for an Engagement Conducted in Accordance With Generally Accepted Auditing Standards*; and Statement on Standards for Accounting and Review Services (SSARS) No. 26, *Quality Management for an Engagement Conducted in Accordance With Statements on Standards for Accounting and Review Services*.

⁹⁸ See Briefing Paper for the Standing Advisory Group, *Designing and Implementing a System of Quality Control* (Oct. 13, 2010). An archive of SAG

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⁹⁰ See, e.g., the UK Financial Reporting Council, *Audit Firm Governance Code* (Apr. 2022) available at https://www.frc.org.uk/getattachment/5af7cdb7-a093-4da8-94d7-f4486596e68c/FRC-Audit-Firm-Governance-Code_April-2022.pdf, and the Japan Financial Services Agency, *Audit Firm Governance Code* (Mar. 2017) available at <https://www.fsa.go.jp/news/28/sonota/20170331-auditfirmgc/3.pdf>.

⁹¹ See, e.g., 2018 Inspection Observations Preview at 1–4.

⁹² See, e.g., COSO, *Internal Control-Integrated Framework* (May 2013). An executive summary of COSO’s internal control framework is available at <https://www.coso.org/files/ugd/3059fc1d7d5dd38074006bce8df621a942cf.pdf>.

⁹³ More information about ISO 9000:2015 is available at <https://www.iso.org/standard/45481.html>.

⁹⁴ See Benefits of related frameworks below.

the SAG discussed how QC standards may benefit from stronger requirements and other enhancements with respect to, for example, firm culture and tone at the top, firm risk assessment, and monitoring of the quality control system, including use of root cause analyses.⁹⁹ In 2018, the SAG discussed whether additional or more specific direction in the quality control standards with respect to governance and leadership would lead to enhancements in firm quality control systems.¹⁰⁰ Advisory group members have generally supported including requirements concerning firm governance and leadership in PCAOB QC standards.

Rulemaking History

On December 17, 2019, the Board issued the concept release to explore the possibility of revising PCAOB QC standards. The concept release described an approach similar to the approach taken by the then-proposed ISQM 1, with certain differences and alternative requirements to specifically address the PCAOB's objectives, including establishing requirements that:

- Align with U.S. Federal securities law, SEC rules, and other PCAOB standards and rules;
- Retain important topics in current PCAOB QC standards;
- Address specific emerging risks and problems observed through PCAOB oversight activities; and
- Provide more definitive direction to prompt appropriate implementation of certain requirements.¹⁰¹

The Board received 36 comment letters in response to the concept release.¹⁰² Commenters included firms and related groups, investors and

related groups, academics, trade groups, and others.

On November 18, 2022, the Board issued a proposal to supersede current PCAOB QC standards with an integrated, risk-based standard, QC 1000, *A Firm's System of Quality Control*, that would apply to all registered firms. The Board received 42 comment letters in response to the proposal.¹⁰³ Commenters included firms and related groups, investors and related groups, academics, trade groups, and others. The Board has considered all comments in developing the final standard and related amendments, and commenter input is included where relevant in the discussion that follows.

Areas of Improvement to the QC Standards

Taking into account the foregoing considerations, as well as careful consideration of comments received, the Board adopted changes to its QC standards that it believes will drive significant improvements in firms' QC systems, by:

- Emphasizing accountability, firm culture and the "tone at the top," and firm governance through requirements for specified roles within and responsibilities for the QC system, including at the highest levels of the firm; quality objectives that link compensation to quality; and, for the largest firms, the requirement of an independent perspective on firm governance;
- Striking the right balance between a risk-based approach to QC—which should drive firms to proactively identify and manage the specific risks associated with their practice—and a set of mandates, including mandatory quality objectives; mandatory processes for risk assessment, monitoring and remediation, and QC system evaluation; and specific requirements in key areas—which should assure that the QC system is designed, implemented and operated with an appropriate level of rigor;
- Addressing changes in the audit practice environment, including the increasing participation of other firms and other outside resources, the role of firm networks, the evolving use of technology and other resources, and the increasing importance of internal and external firm communications;
- Broadening responsibilities for monitoring and remediation of deficiencies to encourage an ongoing

feedback loop that drives continuous improvement; and

- Requiring a rigorous annual evaluation of the firm's QC system and related reporting to the PCAOB, certified by key personnel, to underscore the importance of the annual evaluation of the QC system, reinforce individual accountability, and support PCAOB oversight.

In the Board's view, the basic objectives of the QC system should be the same for all firms, but the scope of the QC standard and how it applies should take into account wide disparities in nature and circumstances across registered firms, in particular the extent to which their practices include engagements required to be performed under PCAOB standards, and the complexity of such engagements. The risks that firms face, and therefore the specific policies and procedures necessary to appropriately serve investor interests through an effective QC system, vary significantly from the largest firms, operating as part of global networks, to local firms or sole proprietorships. The scalability of the new QC standard is discussed in greater detail below.

QC 1000: Basic Structure, Terminology, and Scalability

Basic Structure

1. Considerations Informing the Structure of QC 1000

Informed by its observations and assessment of changes to auditing practice, the Board believes it is critical that its new QC standard strikes an appropriate balance between risk-based elements, which should drive firms to proactively identify and manage the specific risks associated with their practice, and a set of mandates to assure that the QC system is designed, implemented, and operated with an appropriate level of rigor. Moreover, the Board believes the new QC standard should foster a proactive approach to QC that drives continuous improvement. Based in part on its observations, the Board also believes its new standard should include specific requirements for some important areas of the QC system that are addressed more generally in current PCAOB QC standards, such as firm governance and leadership, technology and other firm resources, and firm communications.

QC 1000 addresses all the areas of QC that Sarbanes-Oxley requires PCAOB QC standards to address, which the Board believes will provide a robust framework for a firm's QC system. It incorporates eight components, which are based on mandatory elements and

meeting agendas, briefing papers, and webcasts is available at <https://pcaobus.org/about/advisory-groups/archive-advisory/standing-advisory-group/sagmeetingarchive>. The materials for the Oct. 13–14, 2010, SAG meeting are available at https://pcaobus.org/news-events/events/event-details/standing-advisory-group-meeting_476.

⁹⁹ See Briefing Paper for the Standing Advisory Group, *Initiatives to Improve Audit Quality—Root Cause Analysis, Audit Quality Indicators, and Quality Control Standards* (June 24, 2014) ("June 2014 SAG Briefing Paper"). The materials for the June 24–25, 2014, SAG meeting are available at https://pcaobus.org/news-events/events/event-details/pcaob-standing-advisory-group-meeting_772.

¹⁰⁰ See Briefing Paper for the Standing Advisory Group, *Quality Control: Governance and Leadership* (Nov. 29, 2018). The materials for the Nov. 29, 2018, SAG meeting are available at https://pcaobus.org/news-events/events/event-details/standing-advisory-group-meeting_1137.

¹⁰¹ See Concept Release at 6.

¹⁰² The comment letters received in response to the concept release are available on the Board's website in Docket 046.

¹⁰³ The comment letters received in response to the proposal are available on the Board's website in Docket 046. In addition to 42 letters received from commenters, Docket 046 includes an analysis prepared by the PCAOB Office of Economic and Risk Analysis.

mandatory processes that create a basic structure applicable to all firms. For example, as discussed in more detail below, QC 1000 establishes mandatory, outcome-based quality objectives and mandatory processes for risk assessment and monitoring and remediation. Within the structure created by these mandates, firms will develop their own policies and procedures based on the specific risks created by their circumstances and practice. QC 1000 also includes requirements for annual evaluation of the QC system and reporting to the PCAOB on that evaluation, which the Board believes will add rigor and accountability to the firm's evaluation of whether the QC system has met its objectives, and will strengthen the feedback loop that drives continuous improvement.

The structure itself addresses areas that current PCAOB standards do not directly address, such as firm governance and leadership, technology and other firm resources, and firm communications. In addition, to the extent it is principles-based and focused on the specific risks faced by the firm, the structure is inherently scalable and can be applied to firms of all sizes and circumstances.

The structure of QC 1000 has commonalities with the structure of ISQM 1 and SQMS 1. While the approach taken in ISQM 1 and SQMS 1 has informed the Board's thinking, the Board has carefully analyzed every aspect of that approach and considered where to align and where to further strengthen the PCAOB standard by including alternative or incremental provisions that the Board believes will better serve investor protection and the public interest. The Board believes that building on a well-understood basic framework, appropriately tailored and strengthened to address its legal and regulatory environment and its investor protection mandate, will enable firms to implement and comply with QC 1000 more effectively. In designing, implementing, and operating their QC systems, firms that are subject to both PCAOB standards and IAASB or AICPA QC standards—which the Board believes constitute a very substantial majority of firms that perform engagements under PCAOB standards¹⁰⁴—can leverage the work they have already done and the investments they have already made to comply with those other requirements.

Many commenters, including firms and related groups, were generally supportive of structuring QC 1000 in a

manner similar to the structure of ISQM 1 and SQMS 1. However, several commenters, including firms and related groups, suggested that further alignment should be considered, and any differences should be minimized. Several commenters suggested that firms would be subject to at least two different quality management/quality control systems, and commented that this would be impractical for firms to operate. The Board does not believe that QC 1000 conflicts with the requirements of other standard setters or that anything prevents firms from developing a single QC system for their entire practice that satisfies both PCAOB requirements and other professional standards to which the firm is subject. The Board acknowledges certain differences between QC 1000 and the quality management standards set by other standard setters, in particular areas where QC 1000 establishes additional or more stringent requirements. However, the Board believes that quality responses developed by firms under QC 1000 can be considered by firms for the purposes of other quality management standards to which they are subject, reducing the need for two or more separate QC systems.

One investor-related group did not support the framework of the standard, arguing that ISQM 1 is a process-driven and compliance-oriented framework that does not encourage firms to meaningfully enhance their QC systems for the benefit of investors. Another investor expressed concern regarding the reliance on ISQM 1 in the development of QC 1000 on the basis that it does not always reflect the best interests of investors. The Board continues to believe that a common basic structure among quality control standards is beneficial. This is not only cost beneficial, but it also supports a firm's ability to operate a single, consistent QC system over its whole practice, which the Board believes ultimately supports audit quality. Where appropriate, QC 1000 goes beyond ISQM 1 to incorporate more detailed or more stringent provisions that are specifically relevant to the U.S. regulatory environment and investors.

Several commenters supported a principles-based approach to QC 1000. However, some commenters suggested that the specified quality responses throughout the standard impose prescriptive requirements that are not consistent with maintaining a principles-based approach. Others expressed a different perspective, suggesting that the standard was too principles-based, providing the firms with too much flexibility in designing,

implementing, and operating their QC systems. For example, an investor expressed concern that a principles-based approach does not always reflect the best interests of investors. Other investor-related groups expressed concerns that a principles-based approach allows audit firms to conduct their own risk assessment and design their own controls to manage risks, including making the determination of whether QC deficiencies exist and are remediated without any public awareness or accountability. One of these investor-related groups suggested that an emphasis on a risk-based approach will result in little to no change at the largest auditing firms as they believe that this approach is already embedded in their QC systems. Another investor-related group commented that the proposed standard set the bar too low and failed to focus on audit quality and accountability such that it would only perpetuate the status quo.

The Board has retained the approach as proposed. The Board believes that QC 1000 strikes the right balance between mandatory and risk-based elements. As discussed in more detail below, QC 1000 establishes a mandatory minimum set of outcome-based quality objectives that apply to all firms. Firms generally cannot omit or modify any of the quality objectives set out in the standard. Therefore, firms do not determine the criteria by which their QC systems will be assessed, only the means by which they will meet those criteria. Moreover, QC 1000 establishes requirements with which all firms will have to comply for roles and responsibilities within the QC system and the firm's risk assessment process, monitoring and remediation process, and evaluation process, as well as specified quality responses applicable to all firms in areas that the Board believes justify a more prescriptive approach. It also includes evaluation and reporting requirements that the Board believes will add accountability and rigor to the annual evaluation.

Within that framework, QC 1000 requires firms to develop the policies and procedures they need to achieve the quality objectives and the overall objective of the QC system. The Board believes this more principles-based aspect of the standard will prompt firms to identify and focus on the most relevant risks to quality in the context of their own practice and will make QC 1000 appropriately scalable. This approach also allows for the standard to be operable by firms of all sizes. Smaller PCAOB audit practices can scale down their responses to fit the risks associated

¹⁰⁴ See below for a discussion of the assumptions regarding the baseline.

with a small practice, and as the practice grows, the firm can scale up to respond to new quality risks. In addition, the Board believes that this approach will make it less likely that the standard will need to be amended in the future in response to changes in the auditing environment, including the use of technology.

2. Components of the QC System

Under QC 1000, the QC system consists of eight components that are designed to be highly integrated:

Two process components:

- The firm’s risk assessment process
- The monitoring and remediation process

Six components that address aspects of the firm’s organization and operations:

- Governance and leadership
- Ethics and independence

- Acceptance and continuance of engagements
- Engagement performance
- Resources
- Information and communication

The risk assessment process applies to these six components, requiring firms to:

- Establish outcome-based “quality objectives,” including those specified throughout the standard (i.e., the desired outcomes to be achieved by the firm with respect to that component);¹⁰⁵
- Identify and assess “quality risks” to the quality objectives;¹⁰⁶
- Design and implement “quality responses” (i.e., policies and procedures to address quality risks);¹⁰⁷ and

¹⁰⁵ “Quality objectives” are defined in QC 1000.A10.

¹⁰⁶ “Quality risks” are defined in QC 1000.A12.

¹⁰⁷ “Quality responses” are defined in QC 1000.A11.

- Establish policies and procedures to monitor internal and external changes that may require modifications to the quality objectives, quality risks, or quality responses.

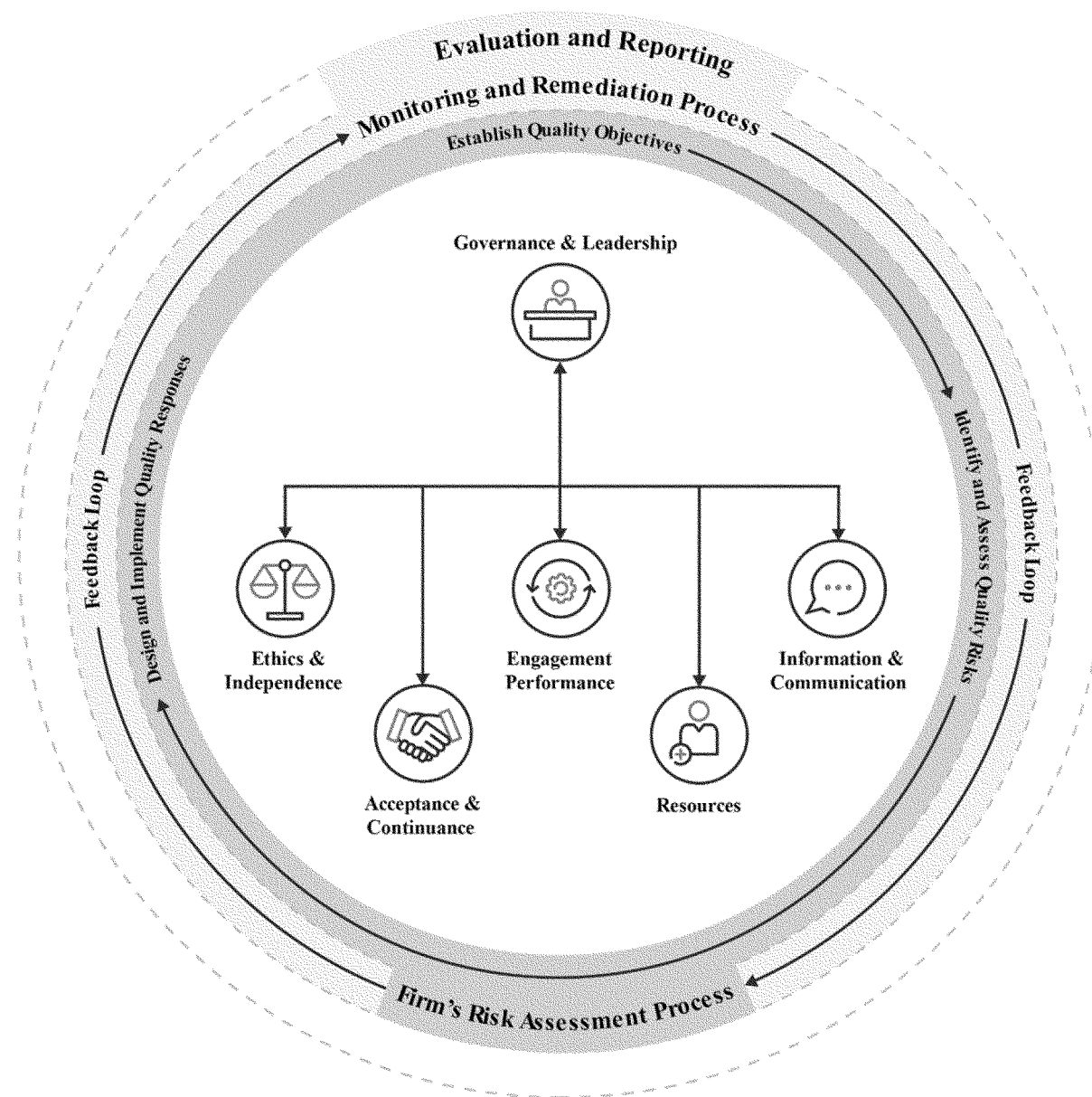
The monitoring and remediation process applies to all of the components of the QC system, including monitoring and remediation itself (i.e., firms are required to identify and remediate deficiencies that are observed in their monitoring and remediation activities).

The firm is also required to evaluate and report on its QC system annually, based on the results of its monitoring and remediation activities.

The following diagram illustrates the structure of the firm’s QC system under QC 1000:

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Structure of the Firm's QC System



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3. Quality Objectives, Quality Risks, and Quality Responses, Including Specified Quality Responses

For each of the six components to which the risk assessment process applies, QC 1000 specifies required quality objectives. While QC 1000 provides some flexibility with regard to the quality risks that firms are required to identify and the quality responses that firms are required to develop to address those risks, it does not provide the same flexibility with regard to quality objectives. Instead, quality objectives that will apply to all firms are

specified in the standard. Firms can establish additional quality objectives—indeed, they are required to do so if necessary to achieve the objective of the QC system—but they generally cannot omit or modify any of the quality objectives set out in the standard. The Board believes that, for many firms, the quality objectives specified in the standard are likely to be comprehensive, and does not expect in the current environment that additional quality objectives would generally be necessary. However, the Board also recognizes that the nature and circumstances of a firm and its engagements will vary and the

environment may change. Accordingly, firms are required to establish additional quality objectives, if necessary.¹⁰⁸ The quality objectives established by this standard set forth a floor rather than a ceiling.

Firms are required to identify and assess quality risks to the achievement of the established quality objectives. They are required to develop quality responses to address the assessed quality risks. Quality responses are defined as policies and procedures

¹⁰⁸ See “The Firm’s Risk Assessment Process” below.

designed and implemented by the firm to address quality risks; policies are statements of what should, or should not, be done to address an assessed quality risk, and procedures are actions to implement and comply with policies. As proposed, the definition of quality responses provided that policies “may be documented or explicitly stated in communications.” In the final rule, that sentence was eliminated to avoid confusion or potential conflict with the documentation requirements set out in QC 1000.81–83.

The correspondence across quality objectives, quality risks, and quality responses is generally not one-to-one. Most quality objectives are likely to have multiple quality risks. Some quality risks may affect one or more

quality objectives, either within a single component or across several components, and may require multiple quality responses. Some quality responses may address multiple quality risks.

Quality responses would typically be specific to the firm, to respond to its particular assessed quality risks. QC 1000 also includes some specified quality responses, which are mandatory for the firms to which they apply. Specified quality responses carry requirements from current PCAOB standards into QC 1000 or provide new requirements that the Board believes are important to a firm’s QC system. The specified quality responses are not intended to be comprehensive; on the contrary, for most of the components of

the firm’s QC system, the standard includes only a few specified quality responses, and for the engagement performance component there are none. As a result, the specified quality responses alone will not be sufficient to enable the firm to achieve all established quality objectives; firms are required to design and implement their own quality responses. Both the specified quality responses and the quality responses the firm designs and implements on its own are critical in addressing quality risks. The following graphic illustrates the relationship between all quality responses (*i.e.*, the quality responses necessary to achieve all established quality objectives) and the specified quality responses established in QC 1000:

The Relationship Between Quality Responses and Specified Quality Responses



Terminology

This section discusses some of the terminology used throughout QC 1000. Appendix A to QC 1000 defines several terms used in the standard.

Two commenters indicated that the proposed terminology was understandable and appropriate, but most commenters on the topic requested

that the terminology used in QC 1000 be consistent with the terminology used by other standard setters, primarily to avoid potential confusion and ensure that the process of evaluating the QC system and the conclusion reached as to its effectiveness would be the same under both standards. The Board continues to believe that its proposed terminology is necessary to capture the

basic concepts used in QC 1000, which differ in some respects from the concepts used by other standard setters, particularly as regards “other participants,” as the Board has defined that term, and the annual QC system evaluation process, which is grounded in the concepts of “engagement deficiency,” “QC deficiency,” and “major QC deficiency.” While this

approach will result in an incremental burden for firms that seek to comply with other QC standards as well as QC 1000, the Board believes that the burden is justified. The Board also believes that, just as firms can perform audits under different auditing standards, they can learn to implement and operate a QC system under different QC standards. Accordingly, with the clarifications described below, the Board adopted the terminology substantially as proposed.

1. Applicable Professional and Legal Requirements

As discussed in more detail below, compliance with applicable professional and legal requirements is a fundamental concept under QC 1000, driving the objective of the QC system as well as many quality objectives and specified quality responses. The proposed standard defined “applicable professional and legal requirements” as

- Professional standards, as defined in PCAOB Rule 1001(p)(vi);
- Rules of the PCAOB that are not professional standards; and
- To the extent related to the obligations and responsibilities of accountants or auditors or to the conduct of engagements, rules of the SEC, other provisions of U.S. Federal securities law, and other applicable statutory, regulatory, and other legal requirements.

Two commenters supported the definition as proposed. One commenter recommended including the profession’s ethical standards explicitly. Two commenters stated the phrase “other applicable statutory, regulatory, and other legal requirements” could be read broadly and extend beyond regulations that directly bear on the conduct of audit engagements. Another commenter suggested amending the definition of “professional standards” in PCAOB Rule 1001(p)(vi) to refer to “quality control standards” rather than “quality control policy and procedures.”

In response to comments, the Board made changes to the third, more general clause of the definition. As one commenter suggested, the Board expanded the definition to explicitly mention ethics laws and regulations.¹⁰⁹ While the definition as proposed encompassed applicable ethics requirements, the Board believes an express reference will help to remind firms and individuals of the centrality of ethics considerations. The Board also

refined the definition to make clear that it encompasses statutory, regulatory, and other legal requirements beyond professional standards and other PCAOB rules “[t]o the extent related to the obligations and responsibilities of accountants or auditors in the conduct of *engagements* or in relation to the QC system.” This change is designed to limit the breadth of the definition to the relevant circumstances.

The phrase “quality control policies and procedures,” used in PCAOB Rule 1001(p)(vi), is drawn from section 110(5) of Sarbanes-Oxley. The Board believes its rule should continue to align with that statutory provision.

This definition captures all professional and legal requirements specifically related to engagements under PCAOB standards of issuers and SEC-registered broker-dealers, including relevant accounting, auditing, and attestation standards, PCAOB and SEC rules, other provisions of Federal securities law, other relevant laws and regulations (e.g., state law and rules governing accountants), applicable ethics law and rules, and other legal requirements related to the obligations and responsibilities of accountants or auditors in the conduct of the firm’s engagements or in relation to the QC system.¹¹⁰ It does not encompass requirements that apply to businesses generally, such as tax laws, safety regulations, and employment law.

2. Engagement

The proposed standard defined “engagement” as (1) any audit, attestation, review, or other engagement under PCAOB standards performed by a firm, or (2) any engagement in which a firm “play[s] a substantial role in the preparation or furnishing of an audit report” as defined in PCAOB Rule 1001(p)(ii).¹¹¹ In the final standard, the

¹¹⁰ For avoidance of doubt, the requirements relating to compliance with applicable professional and legal requirements are meant to make clear that, as relates to engagements subject to PCAOB standards, all applicable professional and legal requirements must be followed. The requirement does not suggest that application of “other applicable statutory, regulatory, and other legal requirements” could supersede rules of the SEC, other provisions of U.S. Federal securities law, rules of the PCAOB that are not professional standards, or PCAOB professional standards. On the contrary, requirements relating to “applicable professional and legal requirements” are meant to highlight the importance of adhering to other requirements when those requirements do not conflict with or abridge requirements of Federal securities laws, PCAOB rules, or PCAOB standards.

¹¹¹ Generally, and as described in more detail in Rule 1001(p)(ii), a firm plays a substantial role in the preparation or furnishing of an audit report if (1) its engagement hours or fees constitute 20% or more of the total engagement hours or fees or (2) it performs the majority of the audit procedures

term “engagement” encompasses the same scope as it did in the proposal—when the firm leads an engagement as lead auditor or practitioner, or plays a substantial role—but the definition has been restructured for clarity.

The final standard defines “engagement” as any audit, attestation, review, or other engagement performed under PCAOB standards:

- Led by a firm; or
- In which a firm “play[s] a substantial role in the preparation or furnishing of an audit report” as defined in PCAOB Rule 1001(p)(ii).

The definition covers not only circumstances in which the firm serves as the lead auditor or the “practitioner” for an attestation engagement, which is what is customarily meant by the term engagement, but also any substantial role work the firm undertakes. The Board’s view is that this additional breadth is appropriate because playing a substantial role in an engagement for an issuer or broker-dealer is sufficient to require a firm to register with the PCAOB. The definition covers all engagements under PCAOB standards performed by the firm, whether the application of PCAOB standards is legally required (e.g., for audits of issuers and broker-dealers) or undertaken pursuant to contractual agreement, where permitted but not required under SEC rules, or for any other reason.

Commenters on the definition of “engagement” generally supported it. One commenter requested clarification as to why the definition does not include work performed at less than a substantial role, given that the standard includes requirements regarding such work.

The Board defined “engagement” to exclude work performed on other firms’ PCAOB engagements at less than a substantial role because it believes the auditor responsibilities associated with such work, and the risks posed by it, are materially different than the responsibilities and risks associated with a firm leading an engagement or playing a substantial role.¹¹² QC 1000 contains provisions specifically applicable to work performed on other firms’ PCAOB engagements at less than

with respect to a subsidiary or component whose assets or revenues constitute 20% or more of the consolidated assets or revenues of the issuer, broker, or dealer.

¹¹² PCAOB registration rules reflect this difference in risk profile: PCAOB registration is required for firms that lead engagements or play a substantial role in audits of issuers and broker-dealers, but not for work performed on other firms’ engagements at less than a substantial role. See PCAOB Rule 2100, *Registration Requirements for Public Accounting Firms*.

¹⁰⁹ These include those arising under state law or the law of other jurisdictions (e.g., obligations regarding client confidentiality). See QC 1000 footnote 10.

a substantial role, which have been tailored to reflect those responsibilities and risks. The Board believes this tailored approach is appropriate.

Also grounded in the Board's views on relative risk and the investor interests at stake, the concept of "engagement" marks an important distinction in the level of responsibility created under QC 1000: while all registered firms are required to design a QC system that complies with QC 1000, the threshold for a firm to implement and operate the QC system is when the firm has responsibilities under applicable professional and legal requirements with respect to a firm engagement. The distinction between scaled applicability under QC 1000 (for firms that do not have responsibilities with respect to engagements) and full applicability of QC 1000 (for firms that do perform engagements) is discussed in more detail below.

The Board notes, however, that just because work performed on other firms' PCAOB engagements at less than a substantial role is not considered an "engagement" does not mean it is disregarded under the QC system. This work, by itself, does not trigger the requirement to implement and operate the QC system under QC 1000. However, once a firm is required to implement and operate the QC system, the system will operate over all work performed by the firm under PCAOB standards, including work performed on other firms' PCAOB engagements at less than a substantial role. If a firm is required to implement and operate a QC system under QC 1000, the Board believes that the QC system should address every engagement under PCAOB standards in which the firm participates.

3. Firm Personnel

The proposed standard defined "firm personnel" as individual proprietors, partners, shareholders, members or other principals, accountants, and professional staff of a registered public accounting firm whose responsibilities include assisting with: (1) the performance of the firm's engagements; or (2) the design, implementation, or operation of the firm's QC system, including engagement quality reviews. Professional staff refers not only to employees, but also to other individuals who work under the firm's supervision or direction and control and function as the firm's employees. For example, secondees and leased staff would fall under the definition of "firm personnel."

Two commenters agreed with the definition as proposed. Some firms and

related groups objected to including non-employee contractors and consultants as firm personnel, in particular because they are not subject to the firm's performance evaluation or promotion process. These commenters suggested that such persons be classified as other participants instead. One commenter expressed concern about potential exposure due to the differences between QC 1000 and the definitions of employees with Federal, State, and local tax and labor laws.

The Board continues to believe it is appropriate for the definition of firm personnel to include individuals, such as non-employee contractors and consultants, who work under the firm's supervision or direction and control and function as the firm's employees. In light of the range of legal structures and arrangements used by firms in acquiring and deploying staff, the Board believes a definition based exclusively on legal employment would be too narrow. Instead, the final rule retains an approach based on the functional role played by the individual rather than a specific legal relationship.

When the firm is identifying quality risks to quality objectives that include firm personnel, it may identify different risks associated with non-employee contractors and consultants than other firm personnel, and accordingly would have to develop different policies and procedures for them. For example, non-employee contractors and consultants may be evaluated through the contracting process to determine whether the firm should retain them instead of through the firm's formal evaluation framework.

While the Board expresses no view on any tax or labor law consequences, it notes that the definition does not conflate "firm personnel" with employees. On the contrary, the Board acknowledges that firm personnel includes some non-employees.

Some commenters, generally firms and related groups, were opposed to the definition including anyone who "assists with" engagements or the quality control system, as it may include administrative staff. The Board revised the definition of firm personnel to clarify that "professional staff does not include persons engaged only in clerical or ministerial tasks," which aligns with the definition of "Person Associated With a Public Accounting Firm (and Related Terms)" in PCAOB Rule 1001(p)(i).¹¹³

¹¹³ By aligning the QC 1000 definition of "firm personnel" with the definition of "Person Associated with a Public Accounting Firm (and Related Terms)" in this regard, the Board does not

4. Other Participants

Over the years, audits of issuers have increasingly involved the use of entities and individuals outside the firm in performing audit procedures and evaluating audit evidence. In the context of amending the standards governing the involvement of other auditors in an audit, the Board discussed the increasing prevalence and importance of the use of other audit firms and individual accountants outside the firm, such as an EQR not employed by the firm, and the use of auditor-engaged specialists.¹¹⁴ While it may be beneficial, and in many cases essential, to use other participants in some engagements, these arrangements can pose risks because other participants may not be subject to the same quality controls as firm personnel (for example, with regard to personnel assignments, training, supervision, and monitoring).

With respect to work performed in connection with the firm's QC system or the performance of its engagements, QC 1000 defines "other participants" as accounting firms (foreign or domestic, registered or unregistered), accountants, and other professionals¹¹⁵ or organizations, other than firm personnel, whose responsibilities include assisting with the performance of the firm's engagements or the design, implementation, or operation of the firm's QC system, including engagement quality reviews.¹¹⁶

Some commenters expressed concerns with the use of "other participants" throughout the standard. Many commenters said the proposed responsibilities of the firm with regard to other participants were too broad. A few commenters suggested removing the reference to other participants from certain specified quality responses and allowing firms to tailor their responses to quality objectives for other participants. Some commenters were

mean to suggest that only "firm personnel" can be associated persons. "Other participants" can also be associated persons.

¹¹⁴ See Planning and Supervision of Audits Involving Other Auditors and Dividing Responsibility for the Audit with Another Accounting Firm, PCAOB Rel. No. 2022-002 (June 21, 2022), at 13; Amendments to Auditing Standards for Auditor's Use of the Work of Specialists, PCAOB Rel. No. 2018-006 (Dec. 20, 2018), at 10-15.

¹¹⁵ In this context, "professionals" refers broadly to workers who perform other than clerical or ministerial tasks.

¹¹⁶ It should be noted that "referred-to auditors," as that term is defined in the amendments to AS 2101, *Audit Planning*, adopted in PCAOB Rel. No. 2022-002, are not "other participants" under QC 1000 because the referred-to auditor performs its own engagement and does not participate in the engagement of the lead auditor.

specifically concerned about the inclusion of internal auditors and external specialists in the standard through other participants, and believe they are adequately addressed in other standards. Some commenters argued that other participants should not be included in another firm's quality control system because they are covered by their own firm's quality control system.

Some commenters suggested bifurcating the definition into other participants whose responsibilities include assisting with the performance of the firm's engagements and other participants whose responsibilities include assisting with the design, implementation, and operation of the firm's QC system, on the basis that this would enhance clarity regarding to whom the requirements apply. One commenter said the policies and procedures related to other participants would differ depending on the type of other participant (for example, an internal auditor providing direct assistance differs from an auditor, specialist, or engagement quality reviewer) and QC 1000 imposes the same requirements for each type. One commenter supported the definition. One commenter agreed with separately defining "other participants" and "third-party providers."

The final standard reflects the Board's view that, in designing, implementing, and operating its QC system, the firm will have to address not only firm personnel but also other auditors¹¹⁷ and other professionals or organizations that

the firm uses in connection with the firm's QC system or the performance of its engagements. References to other participants are included throughout QC 1000 in a tailored and context-specific way that recognizes the key roles that other participants play.

The Board recognizes that some other participants may be covered by their own firm's quality control system, and that fact may inform the firm's risk assessment with respect to their participation. But the firm's own QC system must address all the work done on the firm's engagements and in connection with the design, implementation, and operation of the firm's QC system itself, regardless of who does it.

Commenters correctly pointed out that specific performance standards exist related to the use of certain types of other participants in an audit, such as other auditors,¹¹⁸ internal auditors,¹¹⁹ and specialists,¹²⁰ but that does not mean that QC over their use in the firm's engagements is unnecessary. In part, the QC system operates to assure compliance with those specific audit standards. But it must also provide more general assurance about the performance of audits in which those types of other participants are involved. For example, the Board expects that the firm's policies and procedures would cover, if applicable, engaging specialists, determining their compliance with ethics and

independence requirements, and communicating with them as part of the firm's quality control system.

The Board does not believe it is necessary for QC 1000 to bifurcate other participants between those that participate in engagements and those that are involved with the QC system. Just because a quality objective or other provision of QC 1000 refers to all types of other participants in the same way does not mean that the firm should respond by treating all types of other participants in the same way. On the contrary, the firm's policies and procedures addressing other participants should differentiate based on the types and roles of other participants to the extent necessary to be responsive to the firm's quality risks. When designing quality responses, the firm will address the specific risks posed by the other participants and their responsibilities within the firm's engagements and QC system. For example, a firm that uses a network as a resource in many areas, such as independence tracking and monitoring, engagement performance, information and communication, and monitoring and remediation, would have many quality risks and quality responses related to their use of the network. A smaller firm that only uses one individual from outside the firm as an engagement quality reviewer may have fewer quality risks and quality responses related to other participants to address in its quality control system.

The following diagram provides QC 1000's definitions of "firm personnel" and "other participants" and provides examples of each type:

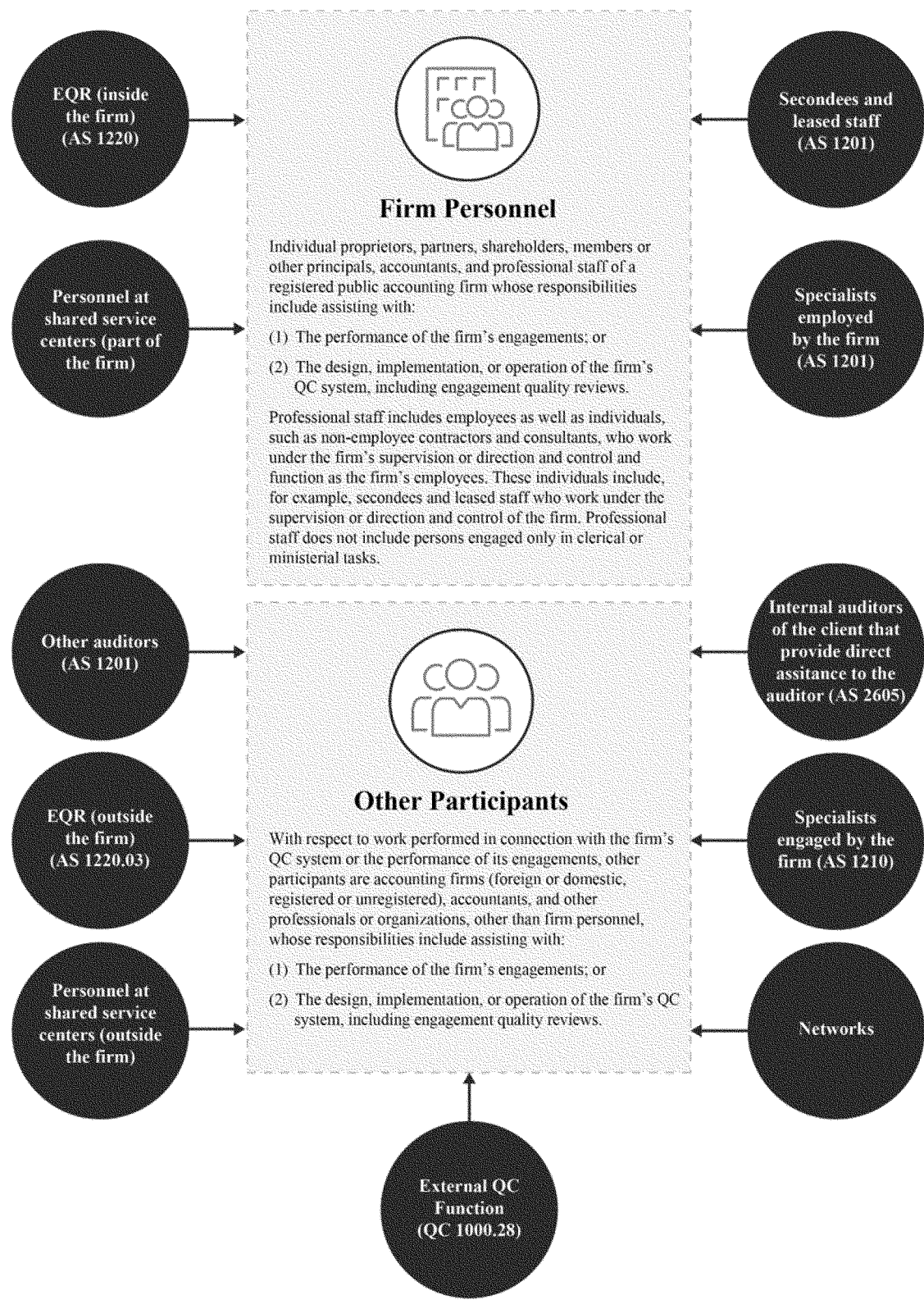
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¹¹⁷ See AS 1205, *Part of the Audit Performed by Other Independent Auditors*, and AS 1201 (which takes effect for audits of financial statements for fiscal years ending on or after Dec. 15, 2024).

¹¹⁸ See, e.g., AS 1201, and AS 1206, *Dividing Responsibility for the Audit with Another Accounting Firm*.

¹¹⁹ See, e.g., AS 2605, *Consideration of the Internal Audit Function*.

¹²⁰ See, e.g., AS 1210, *Using the Work of an Auditor-Engaged Specialist*.



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As noted in the diagram, the persons performing some roles, such as an EQR or personnel at shared service centers, may be firm personnel or other participants, depending on their relationship to the firm. For example, an EQR employed by the firm would be considered firm personnel, whereas an EQR contracted from outside the firm that is not functioning as a firm employee would be an other participant. Similarly, personnel at shared service centers may be firm personnel (if they are employed by the firm or function as firm employees) or other participants (if they are personnel of another organization, such as a network affiliate).

5. Networks

QC 1000 acknowledges that networks of firms may be structured in a variety of ways and could include arrangements between firms for sharing knowledge; developing and implementing consistent policies, tools, and

methodologies; conducting multi-location engagements; or executing other types of business or administrative matters. Through its oversight activities, the PCAOB has observed that some networks provide or require use of a wide range of resources and services and may involve various levels of personnel, composed of a mix of the firm's national and local office personnel. Some examples of resources and services that networks provide include:

- Audit methodologies;
- Technology tools;
- Training;
- Risk management activities;
- Consultations on accounting, auditing, and SEC matters;
- Preventive engagement-level monitoring and coaching;
- Support for inspections; and
- Root cause analysis and remediation.

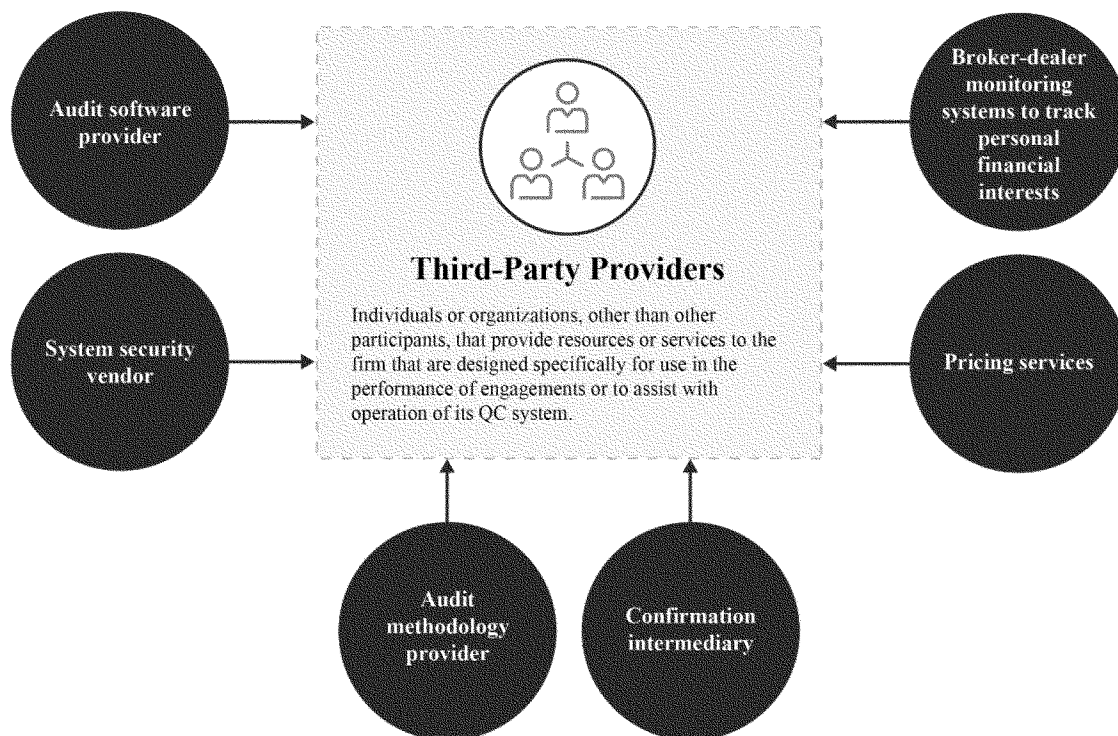
Since networks may involve a wide variety of different arrangements and different degrees of coordination and

cooperation across firms, rather than attempting to define the term “network,” QC 1000 describes these types of arrangements in more general terms.¹²¹ Under the standard, networks may include a combination of registered and unregistered accounting firms and other entities.

6. Third-Party Providers

Commenters on this topic supported the definition of third-party providers as proposed.

The standard addresses resources used by the firm that are sourced from third-party providers. Third-party providers are individuals or organizations, other than other participants, as defined above, that provide resources to the firm that are specifically designed for use in the performance of engagements or to assist in the operation of its QC system.¹²² The following diagram provides QC 1000's definition of “third-party providers” and several examples of them:



¹²¹ In the standard, references to a “network” encompass all of the memberships and affiliations that registered firms must report to the PCAOB in Item 5.2 of their annual report on Form 2, including certain networks, arrangements, alliances, partnerships, and associations. See Item 5.2,

PCAOB Form 2 (describing reporting requirements for memberships, affiliations, and similar arrangements).

¹²² Providers of resources that are not specifically designed for use in the performance of engagements

or to assist in the operation of firms' QC systems (e.g., general word processing and spreadsheet software) are not “third-party providers” as the Board has defined that term.

Scalability

The approximately 1,600 firms registered with the PCAOB differ significantly based on their nature and circumstances:

- Approximately 53% of firms are located in foreign jurisdictions, representing 89 foreign jurisdictions;
- Approximately 20% of total firms, and 40% of firms located in foreign jurisdictions, belong to one of six global networks that contain the largest number of registered, non-U.S. firms that share resources such as methodology and monitoring activities;¹²³
- Approximately 60 firms are sole proprietorships;
- Approximately 650 firms, or 41% of firms, performed an engagement under PCAOB standards for an issuer or broker-dealer during the 12 months ended June 2023;
- Approximately 70 only played a substantial role in such engagements in the past year;
- Approximately 140 performed audits of only broker-dealers in the past year;
- Approximately 130 firms that did not perform an engagement under PCAOB standards for an issuer or broker-dealer in 2022 did perform such an engagement in the past five years; and
- Approximately 51% of firms have not performed an engagement under PCAOB standards for an issuer or broker-dealer in the past five years.¹²⁴

While the Board believes the basic objectives of the QC system ought to be the same across all firms, the Board believes the QC standard needs to be appropriately scalable, so that firms of different sizes and characteristics can

appropriately design their QC system to address the risks associated with their own practice.

The specific policies and procedures necessary to achieve the objectives of the QC system may vary significantly across firms, depending on their size, the types of engagements they perform, and other factors. The Board believes that QC 1000 is sufficiently principles-based and scalable that firms will be able to pursue an approach to QC that is appropriate in light of their specific circumstances.

In the Board's view, firms that perform engagements under PCAOB standards should generally be subject to the same QC requirements. In particular, the Board does not believe the historical distinction between firms that were members of the SECPS in 2003 and those that were not has continuing relevance in determining the QC standards that should apply today. Accordingly, the Board eliminated that distinction. As discussed in more detail below, QC 1000 incorporates certain SECPS requirements, making them applicable to all firms, and eliminates others. However, the Board also believes there are specific areas, such as firm governance, where firms with larger PCAOB audit practices should be subject to enhanced requirements. QC 1000 includes several requirements that apply only to the firms that meet the statutory threshold for annual PCAOB inspection.

The Board is aware that there is a significant number of registered firms that do not perform engagements under PCAOB standards every year—they only participate in other firms' engagements at less than the level of a substantial role or have no involvement in issuer or broker-dealer engagements. The Board believes that the risk to investor protection is minimal if the firm is not performing engagements under PCAOB standards for issuers and SEC-registered broker-dealers, and that it is appropriate to provide for more limited QC obligations in those circumstances. Under QC 1000, all registered firms are required to design a QC system but only firms that are subject to applicable professional and legal requirements with respect to a PCAOB engagement are required to implement and operate the QC system.

1. Scaled Applicability vs. Full Applicability

The Board created a fundamental distinction in QC 1000 between the obligation to design a QC system in compliance with the standard, which

will apply to all firms,¹²⁵ and the obligation to implement and operate an effective QC system, which, broadly speaking, will apply only to firms that perform engagements under PCAOB standards.

Under the standard, firms are required to implement and operate an effective QC system—that is, comply with all provisions of QC 1000—at all times that the firm is required to comply with applicable professional and legal requirements with respect to any of the firm's engagements.¹²⁶

As noted above, many registered firms do not perform engagements every year. However, a firm that is not currently performing any engagements may nevertheless have to comply with applicable professional and legal requirements with respect to a previous or future firm engagement. For example, procedures for the acceptance of a new engagement have to be performed before the engagement is conducted. Responsibilities may also arise with respect to completed engagements long after the issuance of the auditor's report—for example, if the issuer requests the auditor's consent to include its report in a registration statement, if an engagement deficiency is identified that requires remediation, or if the auditor becomes aware of facts that may have existed at the date of the auditor's report which may have affected the report. In the Board's view, whenever a firm has responsibilities under applicable professional and legal requirements with respect to an engagement, those responsibilities should be performed under a QC system that is implemented, is operating, and complies with PCAOB standards.

Importantly, if a firm is required to implement and operate an effective QC system, the firm would not necessarily have to implement and operate every QC policy or procedure that it has designed. An effective QC system provides reasonable assurance that the firm is complying with "applicable" professional and legal requirements. The extent of "applicable" requirements could change depending on the firm's circumstances, and the QC system policies and procedures that the firm would have to implement and operate could change in response. For example, if a firm last performed an engagement (as defined in the standard) five or six years ago and has no current responsibilities with respect to any other firms' engagements, it might be subject only to requirements regarding

¹²³ The six global networks that contain the largest number of registered, non-U.S. firms as reported on Form 2s filed in 2023 are: BDO International Limited, Deloitte Touche Tohmatsu Limited, Ernst & Young Global Limited, Grant Thornton International Limited, KPMG International Cooperative, and PricewaterhouseCoopers International Limited (the member firms of these networks are collectively referred to herein as "GNFs").

¹²⁴ The data were obtained from Audit Analytics and publicly available data from the PCAOB's Registration, Annual and Special Reporting (RASR) available at <https://rasr.pcaobus.org>. The PCAOB does not collect information about whether registered firms perform engagements under PCAOB standards other than for issuers and broker-dealers. Firms may be engaged, for example, in connection with the audit of a reporting company that does not meet the Sarbanes-Oxley definition of "issuer" described in footnote 2 above, in connection with certain offerings of securities that are exempt from registration under the Securities Act (e.g., offerings under Regulation A, Regulation D, or Regulation Crowdfunding), pursuant to a contractual obligation such as a loan covenant, or on an entirely voluntary basis.

¹²⁵ QC 1000.06, discussed below, sets out the requirements for QC system design.

¹²⁶ QC 1000.07.

the retention of certain engagement-related documentation.¹²⁷ In such a circumstance, an effective QC system—*i.e.*, a system that provides reasonable assurance that the firm is complying with applicable professional and legal requirements regarding such documentation—could be scaled back to address only engagement-related documentation retention, as well as ongoing evaluation, reporting, and documentation requirements with respect to the QC system itself. The Board asked in the proposing release whether it was clear how a firm's responsibilities under QC 1000 may change depending on the extent of applicable professional and legal requirements to which the firm is subject at a particular time, and commenters that responded on the issue were generally supportive.

If the firm has no more responsibilities with respect to any engagement, the firm is required to continue operating the QC system until the next September 30 (the annual evaluation date). This would ensure that the firm would be required to evaluate and report on the QC system for any year during which the QC system was required to operate.¹²⁸

Firms that are not subject to the requirement to implement and operate the QC system are still subject to the requirement to design a QC system that complies with QC 1000.¹²⁹ Paragraph .06 of QC 1000, discussed below, sets out the requirements for design of the QC system in more detail.

The Board believes it is appropriate to limit the application of the requirements of QC 1000 for firms that have no obligations under applicable professional and legal requirements with respect to firm engagements. Indeed, in those situations it is hard to see how a firm could, as a practical matter, “implement” or “operate” its QC system. Implementation and operation contemplate, among other things, the application of QC policies and procedures to the firm's engagements, monitoring of work performed on engagements, and identification and remediation of engagement deficiencies. Without “engagements,” as the standard defines that term, implementation and operation of a QC system would be

largely hypothetical. Moreover, the population of firms that are subject only to the design requirements of QC 1000 is comprised entirely of firms that are not required to be registered with the PCAOB—because they do not participate in engagements under PCAOB standards or do so only below the level of a substantial role.¹³⁰

Many commenters, including firms and related groups, investor-related groups, academics, and others, did not support requiring firms that are not required to comply with applicable professional and legal requirements to design a QC system under QC 1000. Several of these commenters expressed concerns that this would be unnecessarily costly to those firms, or suggested that there could be challenges associated with implementing and operating a QC system based on hypothetical risks that could differ from the actual risks at the time the firm accepts and performs engagements pursuant to PCAOB standards. Some commenters suggested that this requirement may cause firms to deregister with the PCAOB, decline to assist U.S. firms in executing their global audits, or create a potential barrier to entry for new firms in the marketplace. One firm-related group commented that as this aspect of the proposal affects such a large number of firms, the potential political impacts deserve further consideration. The firm-related group further commented that foreign firms could see this as an accelerator to a decision to not service specific audit markets, which potentially impacts audit markets beyond the U.S., and that policy makers in other countries may view the potential for further market concentration more significantly.

Firms and a related group raising cost concerns with the proposed QC system design requirements suggested allowing firms that do not perform engagements the flexibility to design their QC system in accordance with another QC standard, such as ISQM 1 or SQMS 1. One of these firms further suggested that firms transitioning to performing engagements under PCAOB standards be given an additional six months to one year from their annual evaluation date to file their Form QC for the transition period. The firm asserted that even if a firm has complied with the design requirements, implementing and operating a QC system that complies

with the standard would involve significant effort. Another firm suggested that it would be more appropriate to have a transition period for the registered public accounting firm to update their system of quality control to adhere to the incremental requirements of the PCAOB. An academic suggested that the design requirements for firms that have not performed and do not plan to perform engagements pursuant to PCAOB standards should be limited to client acceptance components. One firm suggested that the standard could include a requirement that firms are not allowed to perform an engagement under PCAOB standards until they have designed and implemented QC 1000. Other commenters suggested that registered firms that do not intend to conduct PCAOB audits should not be required to do anything under QC 1000.

Other commenters suggested a variety of approaches for when firms should be required to implement and operate a QC 1000-compliant QC system. One firm suggested that firms that only perform a substantial role in more than a certain threshold (presumably to be specified by the PCAOB) of PCAOB engagements could be permitted to comply with ISQM 1 instead of being subject to full applicability of QC 1000. Another commenter suggested that smaller firms (*e.g.*, triennially inspected firms with fewer than 100 issuer engagements) be permitted the option of complying with ISQM 1 or SQMS 1 as an alternative to QC 1000. Another firm suggested that the PCAOB should permit non-U.S. firms to comply with ISQM 1 rather than adopting QC 1000. Another commenter suggested that the criteria for full applicability of the standard should be based on whether the engagements individually or in the aggregate involve a material amount of market capitalization. The commenter suggested that under such an approach, the requirement to operate the QC system could be optional for registered firms auditing companies with a smaller market capitalization.

Some commenters, including a firm, a firm-related group, and an investor, commented that the requirement to design a QC 1000-compliant QC system is appropriate for any registered firm, even if it is not performing engagements or playing a substantial role in other firms' engagements. One firm-related group agreed that whenever a firm has responsibilities under applicable professional and legal requirements with respect to an engagement, those responsibilities should be performed under a fully implemented and operating QC system that complies with

¹²⁷ See AS 1215; 17 CFR 210.2–06.

¹²⁸ QC 1000.07. The proposed requirements for evaluation of and reporting on the QC system are discussed below.

¹²⁹ The standard makes clear that any existing obligations under QC 1000 (for example, reporting obligations with respect to prior periods when the firm was required to implement and operate the QC system) would continue.

¹³⁰ If a firm requests leave to withdraw from PCAOB registration and is permitted to do so, the firm, upon its withdrawal from registration, would no longer be subject to an obligation to design, implement, or operate a QC system in accordance with QC 1000.

PCAOB standards. However, the commenter asked for clarification on the circumstances that trigger the need for a firm to implement and operate a QC system in compliance with QC 1000, and suggested targeted guidance in that area would be helpful.

The Board continues to believe that requiring all registered firms to design a QC system that complies with the standard, regardless of whether they have obligations with respect to engagements, is consistent with the PCAOB's statutory mandate and historical practice. Sarbanes-Oxley directs the PCAOB to include in its QC standards requirements related to numerous topics for "every" registered public accounting firm.¹³¹ The statute also directs the PCAOB that applications for registration with the PCAOB must contain "a statement of the quality control policies of the [applicant] for its accounting and auditing practices."¹³² Consistent with that directive, as a condition to registration, applicants are required to furnish "a narrative, summary description, in a clear, concise and understandable format, of the quality control policies of the applicant for its accounting and auditing practices, including procedures used to monitor compliance with independence requirements,"¹³³ and that description must provide an overview of the applicant's quality control policies regarding each element of quality control.¹³⁴ Therefore, firms that register with the Board are already required to provide a summary of the design of their QC system regardless of whether they have obligations with respect to engagements.¹³⁵

The Board also believes that requiring all firms to design a QC system that complies with all provisions of QC

1000, and not just limiting the requirement to certain components such as acceptance and continuance of engagements, is consistent with its investor protection mandate. While the Board acknowledges that there could be challenges associated with implementing and operating a QC system based on hypothetical risks, it continues to believe that it is important for registered firms to design a QC system based on the quality risks the firm likely would face if it were to perform engagements. Because registering with the PCAOB enables a firm to issue audit reports or play a substantial role on audits performed under PCAOB standards for issuers and broker-dealers, and because investors and companies considering engaging the firm could reasonably expect that any firm that could pursue such an engagement would already have a PCAOB-compliant QC system designed and ready for implementation and operation, the Board believes that imposing a design requirement on all registered firms promotes its mission of protecting investors and promoting the public interest.

As discussed in more detail below, QC 1000 includes requirements that do not appear in other QC standards or that are more prescriptive or more specifically tailored to the PCAOB's legal and regulatory environment than the provisions of ISQM 1 or SQMS 1. Because of these key differences, the Board does not believe that a QC system design based on ISQM 1 or SQMS 1, as suggested by some commenters, would be sufficient. Furthermore, the Board believes that compliance with ISQM 1 may not be the regulatory baseline within certain jurisdictions. The PCAOB has observed other standard setters and regulators adopt variations of ISQM 1, which typically include more detailed and stringent requirements.¹³⁶ Therefore, the Board believes that audit firms within some jurisdictions will already have to design and operate a QC system that goes beyond the requirements of ISQM 1, and it would not be appropriate for the Board to permit compliance with a less stringent quality system than the one required in the local regulatory environment. Similarly, the Board does not believe that it would be appropriate for it to permit firms to comply with their locally applicable variation of ISQM 1 as this would result in the PCAOB requiring and managing compliance

with a multitude of different QC standards.

The Board also continues to believe that, whenever a firm has responsibilities under applicable professional and legal requirements with respect to a firm engagement, those responsibilities should be performed under a QC system that is implemented, is operating, and complies with PCAOB standards. Given the unique features of QC 1000, compliance with ISQM 1 or SQMS 1 would not, in the Board's view, be an adequate substitute, nor would the Board's regulatory purposes be served by providing firms with an extended compliance period after they take on an engagement.

The Board does not believe that this requirement will result in disruption to competition in the audit market. Firms that are subject to applicable professional and legal requirements with respect to engagements, including substantial role engagements, are required to implement and operate a QC 1000-compliant QC system. If a registered firm that has not led an engagement or played a substantial role in the past anticipates the possibility of transitioning to performing engagements, the Board believes the requirement to design a QC system that complies with QC 1000 will facilitate timely implementation and operation of their QC 1000 QC system, which will in turn facilitate appropriate performance of the engagements; appropriate monitoring and, if necessary, remedial action; and timely evaluation and reporting on Form QC.¹³⁷ QC 1000 shares a basic structure and approach with ISQM 1 and SQMS 1, so designing for the incremental features unique to QC 1000 should not be unduly burdensome for firms that are subject to either or both of those other QC standards (which the Board believes will be the case for a very substantial majority of firms that are in a position to perform PCAOB engagements).¹³⁸

The Board does not believe that QC 1000 conflicts with the requirements of other standard setters or that anything prevents firms from developing a single QC system for their entire practice that satisfies both PCAOB requirements and other professional standards to which the firm is subject. The Board

¹³¹ Section 103(a)(2)(B) of Sarbanes-Oxley, 15 U.S.C. 7213(a)(2)(B).

¹³² Section 102(b)(2)(D) of Sarbanes-Oxley, 15 U.S.C. 7212(b)(2)(D).

¹³³ Item 4.1 of PCAOB Form 1 ("Applicant's Quality Control Policies"). The Board modified the information about QC required in Form 1. See below.

¹³⁴ See *Frequently Asked Questions Regarding Registration with the Board*, PCAOB Rel. No. 2003-011F (Dec. 4, 2017) (Question #32), available at https://pcaob-assets.azureedge.net/pcaob-dev/docs/default-source/registration/information/documents/registration_faq.pdf?sfvrsn=c50d7356_0. As part of this rulemaking the requirements in Form 1 are being amended.

¹³⁵ In a separate rulemaking, the Board proposed to create a new form, Form QC—Policies and Procedures ("Form QCPP"), to require that, once QC 1000 becomes effective, any firm that registered with the Board prior to the date that QC 1000 becomes effective must submit an updated statement of the firm's quality control policies and procedures pursuant to QC 1000. See *Firm Reporting*, Rel. No. 2024-003 (Apr. 9, 2024) at 41.

¹³⁶ See, e.g., International Standard on Quality Management (UK) 1, adopted by the Financial Reporting Council (March 2023).

¹³⁷ The Board understands that the actual quality risks the firm faces when it takes on an engagement may differ from the hypothetical risks considered in designing the QC system. QC 1000 requires the firm to establish policies and procedures to monitor, identify, and assess changes to conditions, events, and activities that indicate modifications to the firm's quality objectives, quality risks, or quality responses may be needed, and to make timely modifications as needed. See QC 1000.22–23.

¹³⁸ See Section D.

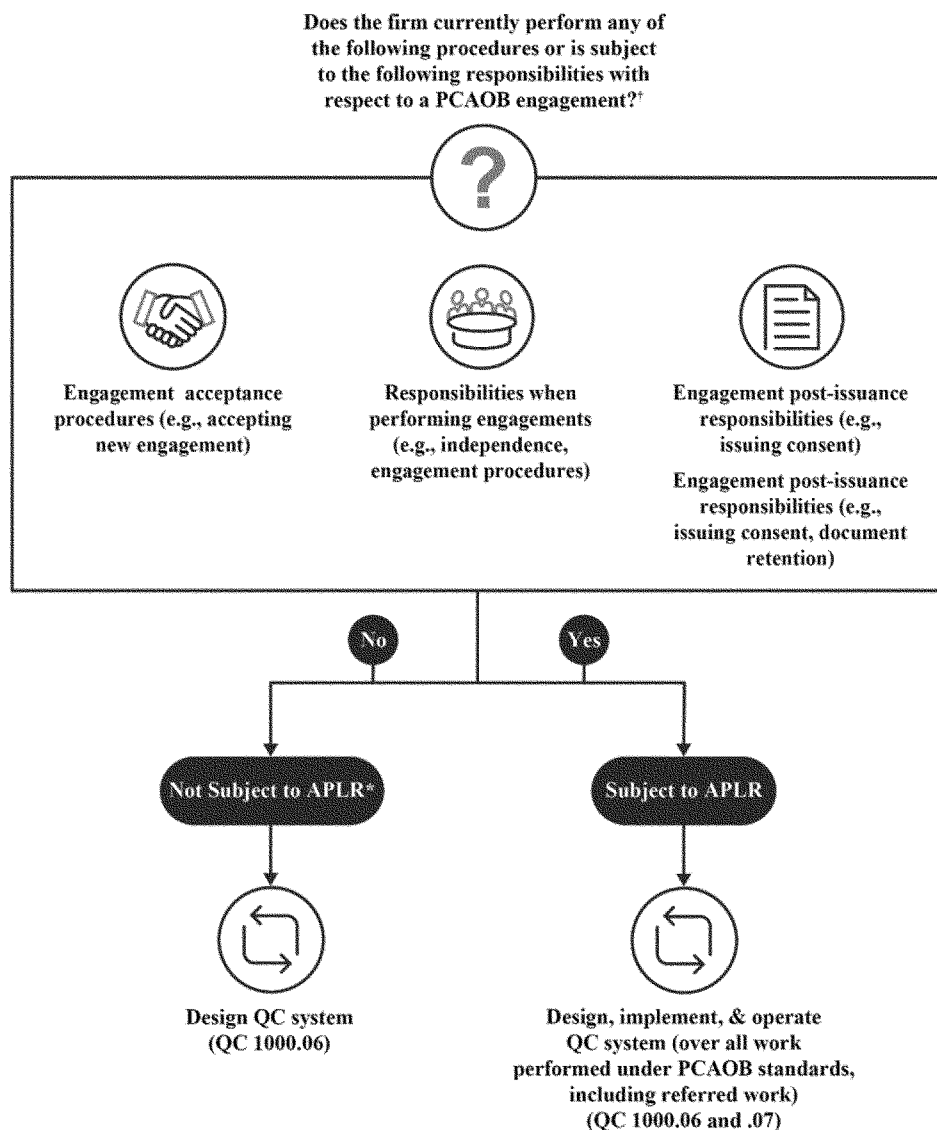
acknowledges certain differences between QC 1000 and the quality management standards set by other standard setters, in particular areas where QC 1000 establishes additional or

more stringent requirements. However, the Board believes that quality responses developed by firms under QC 1000 can be considered by firms for the purposes of other quality management

standards to which they are subject, reducing the need for two or more separate QC systems.

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Decision Tree for Requirements of QC System



[†]An engagement performed by the firm under PCAOB standards or an engagement performed under PCAOB standards by another firm that the firm plays a substantial role in.

*APLR — Applicable professional and legal requirements.

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Firms participating in a PCAOB engagement below the level of a substantial role do not require registration with the PCAOB. If such a firm does not lead and does not plan to lead engagements or play a substantial role in engagements pursuant to PCAOB standards, then the Board believes that the firm should assess whether the costs of complying with the design

requirement are commensurate with their perceived benefit of being registered with the PCAOB.

2. Other Scalability Considerations

Aspects of QC 1000 are risk-based, which makes them inherently scalable. Firms are required to apply a risk-based approach to the design, implementation, and operation of the QC system in the

context of their own audit practice. The standard provides that the firm will tailor the design of its QC system to its specific facts and circumstances, such as:

- The size and complexity of the firm;
- The types and variety of engagements it performs;
- The types of companies for which it performs engagements; and

• Whether it is a member of a network and, if so, the nature and extent of the network relationship.

Several commenters, including firms and a firm-related group, suggested that the proposed standard was too prescriptive. Many of these commenters suggested that, to promote further scalability, specified quality responses could be replaced with quality objectives to allow each firm to develop quality responses appropriate to the circumstances and risks for their firm. One of these firms stated that it disagreed with the notion in the proposing release that a specified quality response suggests that every firm has the same or similar quality risks and that the responses to those risks will also be the same or similar. Another firm suggested that the specified quality responses make the standard inherently less scalable and could be a barrier to entry for smaller firms. The firm further suggested that an overreliance on specified quality responses could discourage firms from performing robust risk assessments and developing tailored quality responses. Other commenters also suggested that more scalability could be incorporated into the standard through consideration of concepts such as professional judgment, relevance, or reliability. Some commenters suggested that further alignment of QC 1000 to ISQM 1 or SQMS 1 would promote further scalability. One firm stated that the standard was overly prescriptive and suggested that specific guidance be provided to small and medium-sized firms focused on operationality of the standard. Several commenters expressed concern that the prescriptive nature of QC 1000 would negatively affect smaller firms.

As discussed above, some specified quality responses carry requirements from current PCAOB standards into QC 1000, while others provide new requirements that the Board believes are important to a firm's QC system. The Board believes that this approach is appropriate and that the specified quality responses are required to address certain quality risks that are present in all firms that perform PCAOB engagements and to assure that the QC system is designed, implemented, and operated with an appropriate level of rigor. The inclusion of specified quality responses in the standard should not be interpreted to suggest that the Board believes all firms have the same or similar quality risks overall; the specific risks addressed by specified quality responses are likely a small subset of the overall population of quality risks identified by a firm, and the Board

expects potentially wide variation in the full set of risks faced by different firms.

The Board believes that the standard incorporates the concepts of professional judgment, relevance and reliability where it is appropriate, for example, in the ability to exercise professional judgment in the determination of whether a major QC deficiency exists, or the discussion in the information and communication component noting that information would have to be both relevant and reliable such that it supports the operation of the firm's QC system and the performance of the firm's engagements in accordance with applicable professional and legal requirements. The Board continues to believe that the inclusion of prescriptive requirements in certain areas promotes its mission of protecting investors and promoting the public interest.

An investor-related group commented that it supports a risk-based approach up to a point, but it expressed concern that the standard placed too much emphasis on scalability and recommended the development of a set of minimum requirements for the establishment of quality control systems. Another commenter stated that the PCAOB should not let scalability concerns get in the way of driving change and improving quality, further suggesting that smaller-firm considerations should not get in the way of doing the right thing for the largest audit firms. One commenter suggested more specific requirements relating to the audits of broker-dealers, commenting that a high deficiency rate in broker-dealer audits suggests the need for more specific requirements with respect to audits of broker-dealers, such as requirements for specific expertise in the conduct of broker-dealer audits, or, to the extent that the broker-dealer is a subsidiary of an issuer, requirements relating to coordination between the broker-dealer audit team and the audit team of the issuer parent company.

The final standard establishes a set of minimum requirements that all firms must follow in the establishment of their QC system. As discussed in more detail below, while QC 1000 provides some flexibility with regard to the quality risks that firms identify and the quality responses that firms develop to address those risks, it does not provide the same flexibility with regard to quality objectives or specified quality responses. Instead, quality objectives and specified quality responses that will apply to all firms are specified in the standard. Firms can establish additional quality objectives—indeed, they are

required to do so if necessary to achieve the reasonable assurance objective—but they generally cannot omit or modify any of the quality objectives or specified quality responses set out in the standard.

Within a uniform basic structure to be used by all firms, QC 1000 reflects a risk-based, scalable approach, particularly in the risk assessment process and the monitoring and remediation process. The nature and extent of these processes would be commensurate with the firm's quality risks and would therefore vary across firms in nature, scope, and complexity. The Board believes it is crucial that the standard be scalable so that firms of different sizes and characteristics can appropriately design their QC system to address the risks associated with their own practice, including specific risks relating to the types of companies that they audit, such as broker-dealers. The Board believes that an appropriate balance between quality objectives and specified quality responses is the best approach to improve quality across firms of all sizes that perform engagements pursuant to PCAOB standards, whether these be issuer or broker-dealer engagements. Similarly, the form, content, and extent of required documentation related to the QC system will be driven by a firm's nature and circumstances. QC 1000 contains both provisions that scale down, by tailoring for smaller PCAOB audit practices, and provisions that scale up, by focusing on risks faced by the largest firms.

Some provisions of QC 1000 focus particularly on firms with a smaller PCAOB audit practice. These include:

- Depending on the nature and circumstances of the firm (including its size and structure), a single individual may be assigned more than one of the QC system oversight roles required under the standard; and
- If the firm issued engagement reports with respect to five or fewer engagements for issuers, brokers, and dealers during the prior calendar year, engagement monitoring activities may include monitoring audits not performed under PCAOB auditing standards. For firms with this number of engagements performed under PCAOB standards, the Board understands that requiring a firm to annually monitor its engagements that are performed under PCAOB standards increases the likelihood of the same partner being inspected every year under QC 1000. The Board believes this could disincentivize partners from serving as the engagement partner and ultimately affect competitive conditions in the market.

Other provisions of QC 1000 impose incremental requirements on firms that issued audit reports for more than 100 issuers in the prior calendar year, including:

- An external oversight function for the QC system composed of one or more persons who are not partners, shareholders, members, other principals, or employees of the firm;
- A program for collecting and addressing complaints and allegations that includes confidentiality protections;
- An automated system for identifying investments in securities that might impair independence; and
- A requirement to perform in-process monitoring of engagements.

These incremental requirements specifically target and respond to potential quality risks that the Board believes are more likely to arise in audit practices of a certain size and complexity. Firms that audit fewer than 100 issuers may still determine that the incremental requirements are an appropriate quality response for quality risks that they have identified specific to their firm, but these are not mandatory for these smaller PCAOB audit practices to promote scalability of the standard.

Several commenters, including firms, suggested that the threshold for any incremental requirements be raised to 500 issuers, to align with the existing SECPS requirement that firms that audit more than 500 SEC registrants have an automated system to identify investment holdings of partners and managers that might impair independence.¹³⁹ One of these firms also suggested a dual-threshold approach that would consider both the number of issuers audited and the market capitalization of the issuers. Two commenters, including an investor-related group and an academic, suggested that there should not be a threshold for incremental requirements, and all requirements of the standard should apply to all firms regardless of the size of the firm. The academic suggested that the incremental requirements may give rise to actual or perceived differences in audit quality between larger audit firms that issue audit reports for more than 100 issuers and smaller audit firms that issue audit reports for fewer than 100 issuers. One firm suggested that the incremental requirements only apply to those firms subject to annual inspection under the PCAOB's rules (in case the 100-issuer threshold for regular inspection in Rule 4003, *Frequency of Inspections*, ever

were changed), and another firm suggested that these should only apply to the top six firms.

Two investor-related groups suggested that if the final standard does include a threshold for certain incremental requirements, the threshold should relate to the market capitalization of the issuers that the firm's audit practice covers rather than the number of issuer audit reports the firm issues. Other commenters were also supportive of a market capitalization-based threshold.

Several commenters suggested that the nature of the firm's audit practice be taken into consideration when determining the applicability of the incremental requirements, and that just looking to the number of issuers may not be an appropriate measure for the size or complexity of the audit practice. One commenter suggested that the proportion of the PCAOB audits to the size of the practice within a firm is also a relevant factor to consider. Some commenters suggested that imposing a threshold of 100 issuers could impose a barrier to entry for firms that wish to expand their audit practices beyond 100 issuers and, as a result, firms may manage their practice to stay below the 100-issuer threshold.

The Board believes that requiring certain incremental requirements of firms with larger PCAOB audit practices is appropriate and that the complexities inherent to large and complex firms are likely to give rise to quality risks for which the incremental requirements would be appropriate quality responses. Based on the comments received, the Board considered whether alternative measures could be used that looked to the nature and complexity of the issuers being audited, for example, through a market capitalization-based threshold. The Board believes it is appropriate to retain the threshold as proposed, based on the size of a firm's issuer audit practice rather than referencing the size of the companies subject to audit by the firm.

In general, the Board believes that the number of issuers is the most indicative measure of a firm's size and the complexity of its audit practice. Under a market capitalization measure, a firm that audits a single very large issuer could look like a large firm, but its practice may well be less complex than a firm that audits a large number of small issuers. The incremental requirements in QC 1000 respond to specific issues or risks—firm governance, confidential handling of complaints and allegations, tracking investments that may bear on independence, and monitoring of in-process engagements—that the Board

believes are more significant in complex practices handling large numbers of engagements. Therefore, the threshold was adopted as proposed.

In addition, the Board believes that larger PCAOB audit practices that audit a greater number of issuers are more likely to have the resources to be able to effectively comply with the incremental requirements at a level commensurate to the risk.

The Board also believes that firms are familiar with the proposed threshold of issued audit reports for more than 100 issuers, because it is used to determine which firms are subject to annual PCAOB inspection.¹⁴⁰ The Board does not believe it to be appropriate to increase the threshold to 500 issuers or to specifically limit the requirements to certain firms. The Board believes that firms that audit between 100 and 500 issuers are sufficiently large such that potential quality risks may arise as a result, and that the incremental requirements would be responsive to these risks.

Several commenters suggested that a cut-off date for the measurement of the size of the firm's issuer practice relative to the 100-issuer threshold, and a related transition period after a firm passes the 100-issuer threshold, be specified in the standard to allow time for firms to implement the incremental requirements. One of these commenters specifically requested consideration of the effective date for the implementation and operation of the incremental requirements if, because of a merger or acquisition, the resultant firm performs audits of more than 100 issuers.

The standard specifies a measurement cut-off date for the 100-issuer threshold of the prior calendar year-end. Therefore, if a firm has issued audit reports with respect to more than 100 issuers in the period January 1 to December 31, in any given year, the firm must implement the incremental requirements beginning the following January 1 and evaluate compliance with the incremental requirements as of the following September 30. The Board believes that firms continuously track the size of their issuer audit practice for the purpose of monitoring the threshold for annual inspection by the PCAOB. Therefore, prior to the calendar year-end measurement cut-off date, the Board expects that firms should have an informed view as to whether they will need to design, implement, and operate the incremental requirements for the

¹³⁹ See SECPS 1000.46 (requirement 4).

¹⁴⁰ See section 104(b)(1)(A) of Sarbanes-Oxley, 15 U.S.C. 7214(b)(1)(A); PCAOB Rule 4003, *Frequency of Inspections*.

following year. Similarly, the Board believes that a merger or acquisition between firms would take time to finalize such that the firms would have an informed view of whether the incremental requirements would be applicable to the successor firm, providing additional time for the firms to design, implement, and begin operating the incremental requirements. In addition, the Board does not believe that it is appropriate or consistent with its investor protection mandate to allow a firm that audits over 100 issuers to not operate the incremental requirements beginning the calendar year following the date of the merger or acquisition if that merger or acquisition resulted in the firm auditing more than 100 issuers. The Board believes that specific quality risks could arise as the result of a merger or acquisition; for example, a sudden increase in the size of the firm could exacerbate the potential quality risks that exist as a result of a firm's size, to which the incremental requirements would be responsive. Furthermore, there is nothing in the standard that prevents firms from implementing the incremental requirements earlier than required, if they believe it to be likely that the threshold will be met.

QC 1000: A Firm's System of Quality Control

Introduction

This section describes the requirements of QC 1000 and highlights the key differences between the final standard and current QC standards. Terms defined in Appendix A to QC 1000, *Definitions*, are italicized throughout QC 1000.

The introduction section of the standard sets up the structure for providing the standard's requirements. Paragraphs .01–.02 describe the risk-based approach to the firm's QC system and acknowledge the important role of the QC system—supporting consistent performance of engagements in accordance with applicable professional and legal requirements—in protecting investors through the preparation of informative, accurate, and independent engagement reports. To emphasize the auditor's role in investor protection, the Board added language to the final standard reminding auditors that the firm's QC system enhances investors' ability to rely on engagement reports. The Board also reversed the order of paragraphs .01 and .02 to improve flow.

One commenter suggested a risk-based approach to quality control with minimum requirements integrated into it, instead of a purely risk-based

approach. The Board agrees that a purely risk-based approach would be inappropriate. As proposed and as adopted, QC 1000 is not a purely risk-based standard. It establishes mandatory quality objectives that every firm is required to achieve; lays out detailed, required processes for risk assessment, monitoring and remediation, and annual evaluation of the QC system; requires specified quality responses in many areas; and fosters accountability and rigor through mandated key roles for the QC system with specified individual responsibility and accountability and required reporting to the PCAOB.

The Firm's QC System

1. QC 1000

a. Objective of the QC System (QC 1000.05)

The proposal asked if the reasonable assurance objective was appropriate and if there were additional objectives that the QC system should achieve. Many commenters, including firms, supported the reasonable assurance objective and did not support additional objectives for the QC system.

Some commenters, including investors and investor-related groups, said there should be an explicit acknowledgement that auditing serves a public purpose and that the system of quality control therefore should serve investors. Other investors and investor-related groups suggested that the quality control system should seek a higher performance standard than mere compliance. Two commenters suggested that the objective should be expanded, so that in addition to complying with applicable professional and legal requirements, engagements should be performed in a manner that is responsive to the needs of investors by ensuring high-quality financial reporting. Another suggested that the foundation of the system should promote high-quality and “useful” financial and non-financial information and achieve a high level of transparent financial reports. The commenter also suggested removing the qualifier “reasonable” and emphasizing that the term “assurance” refers to a high level of assurance.

The Board agrees with these commenters that QC 1000 should frame auditor responsibilities in terms of investor protection, and revised paragraph .05 to reinforce that, as discussed in more detail below. The Board also considered broadening the objective of the QC system beyond compliance in a number of ways, as suggested by commenters.

For example, the Board considered adding explicit references to “investor needs” to the QC system objective. However, the Board are concerned that the concept of “investor needs” is too vague and indefinite to be interpreted consistently as an objective of the QC system. Consistent with the reasonable assurance objective, the Board believes that all investors want informative, accurate, and independent engagement reports. But beyond that, investors are not monolithic and may have different preferences. For example, the needs of a large institutional investor with an actively managed portfolio are different from those of a retail investor holding index funds. Investor needs could also vary across issuers and different types of financial instruments, as well as with changes in market conditions. As a result, the Board does not believe that a QC system objective that was expressly phrased in terms of satisfying “investor needs” would be capable of consistent interpretation or would provide firms with sufficient notice or direction about the conduct required of them.

The Board believes that “high-quality” and “useful” financial reporting suffer from the same issues. These terms are subjective, indefinite, and would mean different things to different financial statement users and in different situations. In addition, grounding auditor obligations in the quality or utility of financial reporting risks conflating the role of the auditor with the role of the preparer. The fundamental responsibility for financial reporting lies with the company. The auditor enhances investors' ability on company financial information through the preparation and issuance of informative, accurate, and independent engagement reports, but the company prepares the financial statements and retains ultimate responsibility for them.

The Board considered one commenter's suggestion of phrasing the objective in terms of “assurance,” rather than “reasonable assurance.” However, the Board believes that this would weaken, rather than strengthen, the standard, in that it could be read to suggest that any level of assurance, even if less than reasonable assurance, would be appropriate. As proposed, the final standard includes a note emphasizing that reasonable assurance is a high level of assurance.

Accordingly, the Board has not revised the objective of the QC system as these commenters suggested. The Board continues to believe that investor needs will be best served through an objective that is grounded in auditors' existing obligations and can be

interpreted clearly and applied consistently. Auditor obligations under applicable professional and legal requirements address investors' fundamental priority: that the financial statements be free of material misstatement. They also clearly delineate what conduct is required, which enables both the Board and the firms that the Board regulates to interpret and apply them on a consistent basis.

The Board has, however, made revisions to paragraph .05 that the Board believes will be clarifying. The final rule specifies expressly that the firm's objective is to design, and if applicable, implement and operate an effective QC system. Further, although the Board concluded that it could not express the objective of the QC system in such terms, the Board does believe firms should be prompted to remember their critical role in investor protection. With that in mind, the Board revised paragraph .05 to explicitly acknowledge that a properly conducted engagement and related report enhance the confidence of investors and other market participants in the company's information to which the firm's report relates. The Board also revised the paragraph to remind auditors that an effective QC system protects investors by facilitating the consistent preparation and issuance of informative, accurate, and independent engagement reports in accordance with applicable professional and legal requirements.

Paragraph .05 specifies that an effective QC system consistently provides a firm with reasonable assurance that the firm, each member of firm personnel, and each other participant conduct each engagement and fulfill their other responsibilities in compliance with applicable professional and legal requirements, and that each engagement report issued by the firm complies with applicable professional and legal requirements. The Board revised the provision to refer to "each member of" firm personnel, "each" other participant, "each" engagement, and "each" engagement report. This change clarifies that the QC system provides reasonable assurance, not just over the pool of firm personnel, the pool of other participants, and the portfolio of engagements, but over each individual and each engagement. The objective is still reasonable assurance, not absolute assurance. But an effective QC system has to be designed, implemented, and operate in such a way that the firm has reasonable assurance that each individual who performs work on behalf of the firm and each engagement the firm undertakes will

comply with applicable professional and legal requirements.

One commenter asserted that some prescriptive aspects of the standard result in absolute assurance instead of reasonable assurance. The Board disagrees, as it believes this is a misunderstanding of the standard. Specifically, the reasonable assurance objective under QC 1000 is broadly consistent with the Board's current QC standards, as well as ISQM 1 and SQMS 1, all of which contemplate that the system of QC should provide reasonable assurance.¹⁴¹ The Board believes that the combination of quality objectives and specified quality responses in QC 1000 establishes a balance between prescriptive requirements and a risk-based approach that contributes to the firm obtaining reasonable assurance, but does not require absolute assurance. Of course, nothing precludes a firm from going beyond the requirements in QC 1000 when designing its QC system.

One commenter suggested that the concept of reasonable assurance was not clear and could be clarified by retaining a footnote from QC 20 that reinforces that deficiencies in individual engagements do not, in and of themselves, indicate a firm's quality control system is insufficient to provide reasonable assurance. The Board has not retained that footnote. The concept of reasonable assurance should be familiar to auditors; it is a basic concept under the Board's current standards and the Board believes it can be interpreted and applied consistently. In addition, in light of QC 1000's detailed process for the evaluation of the QC system, including the new defined terms "QC deficiency" and "major QC deficiency," discussed below, the Board does not believe such a footnote is necessary. Under QC 1000, firms will determine whether the QC system meets the reasonable assurance objective by determining whether any "major QC deficiencies" exist. The existence of major QC deficiencies indicates that the QC system does not provide reasonable assurance, whereas the existence of QC deficiencies that do not meet the definition of major QC deficiency does not. Since that conclusion is apparent from the definitions, the Board does not believe that the existing footnote is needed.

The "reasonable assurance objective" of the firm's QC system is similar to the objective of the QC system under existing PCAOB standards, except that the current standard requires reasonable assurance as to compliance with applicable requirements and "the firm's

standards of quality" (*i.e.*, the firm's policies and procedures),¹⁴² whereas QC 1000's reasonable assurance objective refers only to applicable requirements. This change reflects the different role played by firm policies and procedures under the Board's current QC standards compared to QC 1000. Firm policies and procedures are the linchpin of current PCAOB QC standards: Most of the Board's current QC standards simply require firms to establish, communicate, document, and monitor specified policies and procedures. Policies and procedures also play an important role under QC 1000, but they would have a different context because of the significant differences in the way in which the standard is structured.

QC 1000 is grounded in the firm's risk assessment process, whereby the firm's quality objectives and the risks to achieving them are identified and addressed by the firm in an ongoing, structured fashion. This risk assessment process drives how the firm develops and refines its policies and procedures; the "quality responses" are designed and implemented to address quality risks. As such, policies and procedures are a means to an end—addressing quality risks—rather than an end in themselves. QC 1000 provides more detailed requirements regarding the structure, scope, and functioning of the firm's QC system, particularly in the monitoring and remediation component, than the Board's current QC standards.

This does not mean that firms' QC policies and procedures are no longer important. On the contrary, they are critical to addressing quality risks and thereby achieving quality objectives and the reasonable assurance objective. However, firms may no longer rely on simply promulgating policies and procedures as the central, and sometimes only, component of their QC system. Compliance with the QC standard ultimately is based on whether the firm has met its quality objectives and the reasonable assurance objective—which are driven by whether the firm's policies and procedures have in fact been effective in addressing quality risks—and on whether the firm has complied with the requirements of the standard in the design, implementation, and operation of the QC system. Another commenter suggested that the QC system should not address firm policies and procedures that go beyond applicable professional and legal requirements, on the basis that it might undermine investor protection by disincentivizing firms from developing policies and procedures that

¹⁴¹ See ISQM 1.14; SQMS 1.15.

¹⁴² See QC 20.03; QC 20.17.

go beyond what is required. For the reasons discussed above, the Board has not included policies and procedures in the reasonable assurance objective. However, because policies and procedures play an important role in the firm achieving the reasonable assurance objective, the Board has determined that some quality objectives have to incorporate compliance with firm policies and procedures as well as applicable professional and legal requirements.

The reasonable assurance objective also reflects the view that the purpose of the QC system is to drive overall compliance by the firm, each member of firm personnel, and each other participant with applicable professional and legal requirements, and not necessarily to drive more narrow compliance with firm policies and procedures.

Under QC 1000, the reasonable assurance objective of the firm's QC system is generally consistent with the objective of the QC system under the Board's existing QC standards but, in addition to the changes discussed above, it places more emphasis in three key areas:

- Expressly reminding auditors that an effective QC system protects investors by facilitating the consistent preparation and issuance of informative, accurate, and independent engagement reports;
- Specifying that responsibilities be fulfilled not only with respect to professional standards, but also with respect to legal requirements to the extent they apply (e.g., SEC and PCAOB rules, other provisions of U.S. Federal securities law, and other applicable legal and regulatory requirements); and
- Expressly mentioning compliant engagement reporting (an existing responsibility under PCAOB standards), given the explicit reference to audit reports in Sarbanes-Oxley.¹⁴³

Responsibilities in this context include all responsibilities that are subject to applicable professional and legal requirements—for example, in relation to the firm's engagements, work the firm does on other firms' engagements, training, independence monitoring, and other activities that are part of or subject to the firm's QC system.

In addition, the objective covers the activities of a broader group than current standards. It applies not only with respect to firm personnel and other auditors, but also to other participants

involved in the firm's engagements and QC activities whose work is performed at the direction of the firm. As discussed above, the Board believes that QC 1000 should reach such other participants in light of, among other things, the increasing prevalence and importance of the use of professionals and organizations outside the firm, such as auditor-engaged specialists and service centers, in audits performed under PCAOB standards. Many commenters, generally firms and related groups, expressed concern about the inclusion of other participants in the reasonable assurance objective. The Board believes that the firm's own QC system must address all the work done on the firm's engagements and in connection with the design, implementation, and operation of the firm's QC system, regardless of who does it. The reasonable assurance objective in QC 1000 appropriately reflects that scope.

b. Requirements To Design, Implement, and Operate a QC System (QC 1000.06–.07)

QC 1000 requires all firms to design a QC system that complies with the standard. This entails assigning QC-related roles and responsibilities as provided in paragraphs .10–.17; establishing quality objectives, at least annually identifying and assessing quality risks to the achievement of those objectives, and designing quality responses to address those risks, as provided in paragraphs .18–.57; designing a monitoring and remediation process that, upon implementation, would comply with paragraphs .58–.76; and documenting the design of the QC system as provided in paragraphs .81–.86. The design of the QC system is based on the quality risks the firm likely would face if it performed engagements.

The PCAOB received a significant volume of comments on this aspect of the proposal, which is discussed above. In addition, one commenter suggested emphasizing the concept of professional judgment by incorporating it in paragraph .06 or .07 and defining it in Appendix A of QC 1000. It is true that under QC 1000, judgment may have to be exercised in areas of the QC system, such as assessing risk and evaluating QC deficiencies. However, the basic approach of QC 1000, which specifies quality objectives to be achieved through specified risk assessment and monitoring and remediation processes, is outcome-based and not simply a matter of professional judgment. Moreover, under paragraph .10, all activities related to the QC system must be performed with due professional care. This means that even in

judgmental areas, professional judgment is not unbounded; individuals must exercise professional skepticism and use the requisite knowledge, skill, and ability to diligently (and in good faith and with integrity) obtain and objectively evaluate information. Accordingly, the Board adopted these requirements as proposed.

In addition to the obligation to design the QC system, firms are required under paragraph .07 to implement and operate an effective QC system (i.e., comply with all provisions of the standard) at all times that the firm is required to comply with applicable professional and legal requirements with respect to any of the firm's engagements.¹⁴⁴ This would occur, for example, whenever the firm has responsibilities with respect to the acceptance of an engagement, the performance of an engagement, remediation of deficiencies in an engagement, or matters associated with an engagement that arise or continue after issuance of the engagement report, such as retention of audit documentation, issuance of reports included in Securities Act filings (including consent to the inclusion of such reports),¹⁴⁵ other engagement deficiencies,¹⁴⁶ and subsequently discovered facts.¹⁴⁷ Once a firm no longer has any responsibilities under applicable professional and legal requirements with respect to any firm engagements, the firm will be required to continue operating the QC system until the next September 30 (the next date as of which the firm is required to evaluate the QC system). This ensures that the firm will evaluate and report on the QC system for any year during which the QC system was required to operate.¹⁴⁸

Note that firms may not have lengthy advance notice before responsibilities arise under applicable professional and legal requirements with respect to an engagement. For example, a firm may be contacted by an affiliated firm to play a substantial role in an engagement or may be asked to consent to the inclusion of a previously issued audit report in

¹⁴⁴ Note, however, that the firm would not necessarily have to implement and operate every QC policy and procedure it has designed. See *Scalability* above.

¹⁴⁵ See AS 4101, Responsibilities Regarding Filings Under Federal Securities Statutes.

¹⁴⁶ See AS 2901. The Board amended AS 2901 in connection with this rulemaking to expand auditor responsibilities with respect to engagement deficiencies. See Amendments to AS 2901, *Consideration of Omitted Procedures After the Report Date, and Related Amendments* below for additional discussion.

¹⁴⁷ See AS 2905, Subsequent Discovery of Facts Existing at the Date of the Auditor's Report.

¹⁴⁸ The requirements for evaluating and reporting on the QC system are discussed below.

¹⁴³ See, e.g., section 103(a)(1) of Sarbanes-Oxley, 15 U.S.C. 7213(a)(1); section 103(a)(2)(B) of Sarbanes-Oxley, 15 U.S.C. 7213(a)(2)(B).

the registration statement of a company previously audited by the firm. Under the standard, registered firms will have to stand ready to have their QC system implemented and operating over such responsibilities whenever they arise.

Although all PCAOB-registered firms are required to design a QC system that complies with the standard, the obligation to implement and operate that system applies only when the firm is required to comply with applicable professional and legal requirements with respect to the firm's engagements. Implementing and operating a QC system means that assigned personnel are fulfilling their QC-related roles and responsibilities under QC 1000, the relevant quality responses (*i.e.*, policies and procedures) and monitoring and remediation process that the firm has designed are operational, and the firm is documenting the implementation and operation of its QC system. As noted above in the discussion of scalability, the scope of the QC system is driven by the professional and legal requirements that apply to the firm and its engagements and the relevant risks, which may vary depending on the nature and extent of the firm's practice.

The standard also makes clear that existing obligations under QC 1000, such as the obligation to evaluate and report on the QC system for periods in which the QC system was required to be implemented and operating, are not extinguished when a firm transitions from full applicability to scaled applicability.

As discussed in more detail above, the Board's view is that requiring all registered firms to design a QC system that complies with QC 1000 is consistent with the PCAOB's statutory mandate, historical practice, and investor protection mission, and that scaling back obligations under QC 1000 to the design of the QC system, as described under paragraph .06, is justified in cases where a firm is not subject to any obligations under applicable professional and legal standards with respect to any firm engagement.

b. Risk-Based Approach (QC 1000.08–.09)

The Board did not receive comments specifically on these paragraphs and adopted them as proposed. These paragraphs require a firm to employ a risk-based approach to quality control, such that the firm proactively manages its QC system and the quality of the work it performs on engagements.

Under the standard, the firm is required to design, implement, and operate a QC system that reflects and

responds to the firm's particular risks through two process components.

- The firm's risk assessment process—establishing quality objectives, identifying, and assessing quality risks to the achievement of those objectives, and designing and implementing quality responses to address the identified quality risks—is applied to all of the aspects of the firm's organization and operations that are covered by the QC system and thus is tailored to each firm's specific facts and circumstances.

- The monitoring and remediation process is carried out in a way that is informed by and responsive to risks—for example, quality risks influence both the selection of engagements to monitor and the design and extent of monitoring activities.

The requirement to evaluate the effectiveness of the QC system supports continued improvement in these risk assessment and monitoring and remediation processes by requiring the firm to evaluate and report on whether the quality objectives and the reasonable assurance objective have been achieved. These requirements are discussed in more detail below.

The aspects of QC 1000 that are risk-based are inherently scalable. In applying a risk-based approach, the firm is required to tailor its QC system to the firm's specific facts and circumstances, including the size and complexity of the firm, the types and variety of engagements it performs, the types of companies for which it performs engagements, and whether it is a member of a network (and if so, the nature and extent of the relationship between the firm and the network). Accordingly, a large, complex firm that performs a wide variety of engagements will likely be required to have a more complex QC system than a small firm that performs a small number of less complex engagements.

2. Current PCAOB Standards

As described above, under current QC standards, a QC system is broadly defined as a process to provide a firm with reasonable assurance that its personnel comply with professional standards applicable to its accounting and auditing practice and the firm's standards of quality.¹⁴⁹ The QC system encompasses the firm's organizational structure, policies adopted, and procedures established to provide that reasonable assurance.¹⁵⁰ Registered firms are required to design, implement,

and operate a system of quality control to provide this reasonable assurance.

Roles and Responsibilities

Expectations of individuals within the QC system are established through the assignment of roles and responsibilities that are essential to a well-functioning QC system. This aspect of the QC system creates clearer lines of communication and decision-making authority and greater accountability for those assigned to such roles. One commenter on the overall requirements supported them as proposed. Some firm commenters also supported the proposed roles and offered operational suggestions, while other firm commenters asserted that the proposed roles and responsibilities were not clear and appropriate for the reasons described in the following subsections.

1. QC 1000

a. Due Professional Care (QC 1000.10)

Paragraph .10 of the standard addresses due professional care in performing responsibilities in relation to the QC system. Due professional care, applicable to all firm personnel and other participants, includes professional skepticism. The concept of due professional care imposes a responsibility upon firm personnel and other participants to observe relevant professional standards including, in the context of quality control, QC 1000. The Board believes that this provision is a helpful clarification because the PCAOB standards describing due professional care do not specifically mention QC activities.¹⁵¹

One commenter urged the PCAOB to clarify the need for professional skepticism by leadership in quality control roles. The Board does not believe specific provisions are needed in that regard, because paragraph .10 applies to all individuals performing QC roles, including those in leadership roles.

The Board has adopted this provision with modifications to align with the descriptions of due professional care and professional skepticism being adopted in AS 1000.¹⁵²

b. Assignment of Roles and Responsibilities (QC 1000.11–13)

The Board proposed to require the highest-ranking executive in the firm to bear ultimate responsibility and

¹⁵¹ A new auditing standard, AS 1000, is being adopted to combine and update the four standards that set forth the general principles and responsibilities of the auditor, including AS 1015, *Due Professional Care in the Performance of Work*. See Auditor Responsibilities Release.

¹⁵² *Id.*

¹⁴⁹ See QC 20.03.

¹⁵⁰ See QC 20.04.

accountability for the QC system as a whole. If a firm has co-principal executive officers, each of them would bear such ultimate responsibility and accountability. The PCAOB did not prescribe the substantive qualifications the highest-ranking executive in the firm should have; the proposal did not include any such criteria (unlike the assigned roles under paragraph .12, which only may be assigned to personnel who have the experience, competence, authority, and time to carry out their responsibilities). The Board's intention was to establish accountability for QC at the highest level within the firm and underscore the critical importance of the QC system. One commenter supported this requirement, as it is analogous to the CEO being jointly responsible for the SEC certifications with respect to the financial statements and internal controls. One commenter requested clarification on the structure of smaller firms where the firm's CEO may not be an audit practitioner and may rely on others to fulfill the requirements of the QC system. The Board believes it is important for the firm's principal executive officer, irrespective of whether that person is an audit practitioner, to be ultimately responsible and accountable for the firm's QC system, because the Board believes that this will lead to more vigorous oversight of the audit practice; benefiting investors and other stakeholders that rely on the firm's work.

The requirement in paragraph .12 of QC 1000 is limited to roles that are expected to exist in any firm and allows each firm to assign these roles based on the nature and circumstances of the firm, provided that those assigned have the experience, competence, authority, and time to enable them to carry out their assigned responsibilities. This approach also addresses scalability; as the note to paragraph .12 makes clear, depending on the nature and circumstances of the firm, one individual may be assigned to more than one of the roles in paragraphs .11 and .12.

A number of commenters suggested that the roles in paragraph .12 should be able to be split into multiple roles or assigned to multiple people. Commenters asserted that the roles, such as operational responsibility for the ethics and independence component, are complex enough to require two individuals. Several of the same commenters expressed that the requirement is generally too prescriptive. Several firms indicated that many firms in larger networks may

commonly have these specified roles filled by individuals outside of the firm and the restriction of these roles to firm personnel may be problematic operationally.

For the roles specified in paragraph .12, the final standard retains the requirement that only one individual may be assigned responsibility for each role. A firm may have multiple individuals or multiple layers of personnel supporting these roles, but the responsibility for the assigned role may not be delegated and will remain with the one assigned individual. For example, a firm could assign one person to ethics-related matters and another person to independence-related matters, as long as both of these individuals report to the person with operational responsibility for the firm's compliance with ethics and independence requirements. The Board acknowledges that some firms may seek assistance from their network or other participants in performing some of their QC-related activities, but the Board believes a single individual within the firm should remain responsible for the operational responsibilities of the assigned roles. Regardless of whether specific tasks are delegated to others, the individual assigned to a specified role remains responsible and accountable for the role's related responsibilities.

Commenters generally supported allowing one person to hold multiple responsibilities under certain circumstances, such as smaller firms with limited resources. Two commenters supported the roles as proposed and one commenter suggested the firm's head of audit practice also be included as a role.

The Board's view is that the roles specified in paragraph .12 would be appropriate for every firm. Provided that the criteria in paragraph .12 of QC 1000 are met, the individual assigned ultimate responsibility and accountability for the QC system also may assume responsibility for all aspects of the QC system, including operational responsibility for the QC system, the firm's compliance with ethics and independence requirements, and the monitoring and remediation process. The Board has not been specific about who should be assigned the roles identified in paragraph .12. A firm may determine, based on its nature and circumstances, that it is appropriate to assign already established leaders to one or more of these roles, such as the head of audit practice as suggested by a commenter.

One commenter requested clarification of the intended role in .12d. The role in paragraph .12d allows firms

to assign operational responsibility for other components (e.g., the resources component) based on the nature and circumstances of the firm. The standard provides firms the ability to add additional roles and responsibilities, if appropriate, and the flexibility to assign one individual to more than one of the roles specified.

The proposal asked if firms would have difficulty filling the assigned roles. Two commenters were optimistic these roles could be filled in light of the requirements. Commenters cited increased liability or workload associated with these roles as potential disincentives that may keep qualified individuals from accepting these roles. Specifically, some commenters asserted that the proposal would lower the threshold for individual liability compared to current requirements, and that the threat of enforcement sanctions would deter individuals from accepting the roles.¹⁵³ One commenter sought clarification on the supervision obligations prescribed under QC 1000 and the Board's authority to bring enforcement actions for failure to reasonably supervise under section 105(c)(6) of Sarbanes-Oxley. One commenter recommended amending paragraph .11 to acknowledge that individuals assigned ultimate responsibility for the QC system as a whole can rely on information provided to them and their responsibility is governed by a good faith standard. Two commenters expressed concern that firms, especially smaller issuer or broker-dealer practices, would have difficulty filling the specified roles. One commenter was concerned with increased accountability and suggested balancing accountabilities such that processes and outcomes, as well as rewards and penalties, are more appropriately weighted.

Current QC standards generally impose responsibilities directly on the firm rather than on individuals. Enforcement actions related to the failure to comply with current QC standards can be brought against individuals for contributing to violations by the firm¹⁵⁴ or for failing to

¹⁵³ Analogous concerns were also raised by commenters in relation to the separate rulemaking *Proposed Amendments to PCAOB Rule 3502 Governing Contributory Liability*, available on the Board's website in Docket 053.

¹⁵⁴ See PCAOB Rule 3502, *Responsibility Not to Knowingly or Recklessly Contribute to Violations*. The Board has proposed to amend Rule 3502 in certain ways, including by changing the standard of conduct for associated persons' contributory liability from recklessness to negligence. See *Proposed Amendments to Rule 3502 Governing Contributory Liability*, PCAOB Rel. No. 2023-007 (Sept. 19, 2023).

reasonably supervise an associated person of the firm who commits certain violations.¹⁵⁵

Under QC 1000, the individuals who are assigned specific responsibilities with respect to the QC system could be charged with violations if they fail to comply with those enumerated responsibilities, as well as for contributing to firm violations or failing reasonably to supervise.¹⁵⁶ As discussed further in the sections that follow, the individuals who fill the roles specified in paragraphs .11 and .12 of QC 1000 have specified responsibilities spelled out in paragraphs .14 through .17 of the final standard. Those individuals must exercise due professional care (*see* paragraph .10), and their failure to properly discharge their duties—for example, to establish or direct the establishment of certain QC-system reporting lines (*see* paragraph .14b), to certify the firm's Form QC report to the PCAOB (*see* paragraphs .14d and .15b), or to timely communicate certain information to others (*see* paragraphs .16b and .17b)—would constitute violations of QC 1000. So while current QC standards generally require either a primary violation by the firm to trigger an individual's potential liability under Rule 3502 or a primary violation by another associated person to trigger a supervisory person's potential liability under section 105(c)(6) of Sarbanes-Oxley, QC 1000 creates a framework in which an individual's failure to discharge prescribed responsibilities could give rise to individual liability without regard to whether primary violations were committed by another.

That is not to say, however, that the individuals filling the roles specified in paragraphs .11 and .12 of QC 1000 no longer can be charged with contributing to violations by the firm or for failing to reasonably supervise an associated person who commits certain violations. Because of the important role played by the individuals filling those roles, their failure to properly fulfill their responsibilities may contribute to violations by their firm. Furthermore, paragraphs .15a, .16a, and .17a of the final standard make clear that the individuals who fill the roles discussed therein are supervisory persons who have supervisory responsibilities under the Board's QC standards, for purposes of section 105(c)(6) of Sarbanes-Oxley.

The Board believes that providing another basis for enforcement against responsible individuals could enhance their accountability for the QC system.

Enhanced accountability emphasizes the importance of the firm assigning roles to firm personnel who have the experience, competence, authority, and time needed to carry out their assigned responsibilities. Although the Board recognizes that some commenters expressed concern about whether individuals would be willing to assume these specified roles, the Board believes that these roles are necessary and appropriate for every firm. The Board also believes that, with appropriate incentives, firms should be able to fill these roles. The PCAOB is adopting these requirements as proposed.

The Board discusses each of the QC roles identified in the standard in the subsections that follow. Paragraph .13 provides that individuals assigned operational responsibilities under paragraph .12 should have a direct line of communication to the individual with ultimate responsibility and accountability for the QC system. This line of communication would provide these individuals the information necessary to perform their assigned roles. One commenter supported a feedback loop between the individuals assigned responsibilities under paragraphs .11 and .12, but sought clarity regarding whether individuals in the roles in paragraph .12 are required to report to the firm's principal executive officer. The Board has not prescribed the firm's reporting structure related to those roles, as it may vary based on the nature and circumstances of the firm.

c. Ultimate Responsibility and Accountability for the QC System as a Whole (QC 1000.14)

The individual assigned ultimate responsibility and accountability for the QC system as a whole reinforces the responsibility and accountability of firm personnel by demonstrating a commitment to quality. The standard emphasizes the role of that individual—by the individual recognizing and reinforcing professional ethics, values, and attitudes through the individual's actions, behaviors, and communications—in establishing a firm's tone at the top and attitude towards quality.

The individual assigned ultimate responsibility and accountability is responsible for establishing, or directing the establishment of, structures, reporting lines, and authorities and responsibilities for the roles involving operational responsibility for aspects of the QC system and the QC system as a whole. For each firm, the approach to fulfilling these responsibilities will be dependent on the firm's nature and

circumstances. For example, in a smaller firm where there are fewer individuals with assigned roles, structures may be less formal. Conversely, for a larger firm, it may be necessary to have multiple individuals in roles with assigned responsibilities or to have multiple layers of personnel supporting different activities. However, ultimate responsibility and accountability cannot be delegated.

Also, the individual assigned ultimate responsibility and accountability is accountable for the design, implementation, and operation of the firm's QC system in accordance with applicable professional and legal requirements and the firm's policies and procedures, as well as for the firm's annual QC system evaluation. The functions performed by the individual with ultimate responsibility and accountability may vary across firms. For example, in a smaller firm, the individual assigned ultimate responsibility and accountability may be directly involved in aspects of the QC system, such as the firm's monitoring and remediation process. In a larger firm, this person may supervise others who perform these activities.

Lastly, the Board proposed requiring the individual assigned ultimate responsibility and accountability for the QC system as a whole, along with the individual assigned operational responsibility and accountability for the firm's QC system as a whole, to certify the firm's annual evaluation of its QC system in a report to the PCAOB. One commenter expressed concern that the certification requirements may create a barrier to firms operating in environments that do not have Sarbanes-Oxley-style reporting requirements. The same commenter also emphasized the certifications may have a disproportional impact on smaller firms that have fewer resources. One commenter suggested that certification by the firm's CEO is an ineffective incentive and a more appropriate incentive would be compensation that was heavily weighted towards effective QC systems.

As discussed further below, the Board believes such certification will lead to increased discipline in the evaluation process and reinforce the accountability of the certifying individuals, and has adopted that requirement as proposed. The Board believes certifications are commonly known among issuers within the regulatory environment and would be familiar to their auditors. The Board also believes the certification requirements will complement the revised provisions in paragraphs .25b and .44g of the final standard, which

¹⁵⁵ See Sarbanes-Oxley sec. 105(c)(6), 15 U.S.C. 7215(c)(6).

¹⁵⁶ See PCAOB Rel. No. 2023-007.

address compensation incentives based on an effective QC system.

d. Operational Responsibility and Accountability for the QC System as a Whole (QC 1000.15)

This requirement did not draw comment and the Board adopted it as proposed. The individual assigned operational responsibility and accountability for the QC system as a whole is accountable for supervising the design, implementation, and operation of the firm's QC system. This includes overseeing the operation of the QC system in achieving the reasonable assurance objective. Depending on the nature and circumstances of the firm, this individual may be the same person assigned ultimate responsibility and accountability for the QC system, or may be assigned other operational responsibilities, such as for ethics and independence or monitoring and remediation.

In carrying out the specified responsibilities, the individual assigned operational responsibility and accountability for the QC system as a whole may be supported by the individuals assigned operational responsibility for the firm's compliance with ethics and independence requirements, the monitoring and remediation process, or other components of the QC system. This includes receiving information from such individuals regarding violations of ethics and independence requirements and the results of the monitoring and remediation process.

Along with the individual assigned ultimate responsibility and accountability for the QC system as a whole, and for similar reasons, the Board has required the individual assigned operational responsibility and accountability for the QC system as a whole to certify the firm's annual report to the PCAOB on the evaluation of its QC system, as discussed below.¹⁵⁷

e. Operational Responsibility for the Firm's Compliance With Ethics and Independence Requirements (QC 1000.16)

Compliance with ethics and independence requirements is essential to the performance of engagements and, in some situations, presents challenging, novel, or complex issues. The current requirements for former SECPS member firms include designating a senior-level partner to oversee the firm's

independence policies and consultation process, among other independence-related activities. Like in the proposal, in the final standard the individual assigned operational responsibility for compliance with ethics and independence requirements will supervise the areas addressed by the ethics and independence component of QC 1000, which include the firm's risk assessment process for ethics and independence and the design, implementation, and maintenance of the firm's policies and procedures related to ethics and independence.

Within the ethics and independence component, there are quality objectives and specified quality responses that address potential violations of ethics and independence requirements, including a quality objective that potential violations are communicated to the individual with operational responsibility for ethics and independence requirements. That individual is then responsible for communicating such violations to the individuals assigned operational responsibility for the monitoring and remediation process and operational responsibility and accountability for the QC system as a whole.

Paragraph .16b, as well as several other requirements in the standard, refers to actions being taken on a "timely basis." In each of these cases, what constitutes "timely" would depend on the underlying matter to which the action relates, including the matter's nature, scope, and impact. Timely communication and action should be sufficiently prompt to achieve its objective. In some cases, for example, where there is a high risk of a severe or pervasive problem, communication and action may have to be immediate to be timely. The only commenter on this term agreed that what constitutes "timely" would depend on the underlying matter to which action relates. The commenter also wanted clarification that the firm's policies and procedures assist in promoting communication such that the appropriate individuals with responsibilities over the firm's QC system become aware of relevant matters in a timely manner, as appropriate for the size and the scale of the firm and relative nature of the matter. Insofar as the comment may be read to suggest that the size and scale of the firm, on its own, is a factor in determining timeliness, the Board disagrees. In the Board's view, timeliness is a function of the nature and significance of the issue (appreciating that the size and scale of

the firm may be relevant in gauging the nature and significance of an issue).

One commenter expressed concern that the prescriptiveness of the communication requirements may detract from the achievement of the intended objectives. Specifically, the commenter was concerned that it may not be appropriate to require communication of all violations to the individual with operational responsibility and accountability for the QC system as a whole.

The specified communications are intended to enable these individuals to take timely and appropriate actions in accordance with their responsibilities. In the Board's view, in order to do that, they need to be apprised of ethics and independence violations. Ethics or independence violations may take a variety of forms, and therefore the nature and extent of the communication may also take a variety of forms commensurate to the severity and pervasiveness of the violation. Leaving aside the question of whether a violation of ethics or independence requirements could ever be insignificant, individual violations may evidence problems within specific areas of the firm's policies and procedures or an overall pattern of disregard for ethics and independence requirements that requires timely intervention. The Board has adopted these requirements as proposed.

f. Operational Responsibility for the Monitoring and Remediation Process (QC 1000.17)

The monitoring and remediation process is a critical part of a firm's QC system because it creates a feedback loop to inform the firm's risk assessment process, results in an approach that drives continuous improvement, and provides the firm with information about whether the QC system is operating effectively. As proposed, the individual assigned operational responsibility for the monitoring and remediation process would be responsible for supervising the design, implementation, and operation of the monitoring and remediation process component and the evaluation of the QC system. This individual would also be responsible for overseeing actions taken to respond to identified engagement deficiencies, QC deficiencies, and major QC deficiencies.

One commenter was concerned that it would be a conflict of interest for this individual to oversee both the monitoring and remediation process and the evaluation process. Another commenter recommended that the responsibility for the annual evaluation

¹⁵⁷ If the same person were assigned both ultimate responsibility and accountability and operational responsibility and accountability for the QC system, that person would sign the certification in both capacities.

be shared between the individual with operational responsibility for the QC system as a whole, who recommends the evaluation conclusion, and the individual with operational responsibility for the monitoring and remediation process, who concurs or recommends changes to the conclusion. The Board understands that in a smaller firm these roles may all be performed by the same individual. In a larger firm that assigns different individuals to the roles, the individual with operational responsibility for the monitoring and remediation process supervises the evaluation process. Although the individual overseeing the monitoring and remediation process also oversees the evaluation process, other aspects of QC 1000 drive accountability for the evaluation. Paragraph .14c makes the individual assigned ultimate responsibility and accountability for the QC system as a whole accountable for the annual evaluation. Additionally, paragraphs .14d and .15b impose certification requirements that also drive accountability for the evaluation process. The Board has adopted this requirement as proposed.

The individual assigned operational responsibility for the monitoring and remediation process is also responsible for communicating, on a timely basis, matters related to monitoring and remediation to the individuals assigned ultimate responsibility and accountability for the QC system as a whole and operational responsibility and accountability for the QC system as a whole. These communications would include key aspects of the monitoring and remediation process, such as the monitoring activities performed, results of the monitoring activities, and the remedial actions taken. The communication of this information to the individual assigned ultimate responsibility and accountability for the QC system as a whole facilitates and supports that individual's overall accountability for the evaluation of the QC system.

2. Current PCAOB Standards

QC 20.22 requires the assignment of responsibility for the design and maintenance of QC policies and procedures to appropriate individuals but does not specify the role or roles to which such responsibilities should be assigned. In addition, members of the SECPS are required to designate a senior-level partner responsible for, among other things:

- Overseeing the functioning of the firm's independence policies and consultation process;

- Maintaining the restricted entity list and providing it to all professionals; and
- Supervising the monitoring system related to overseeing that independence violations are addressed.

QC 1000 retains and expands on these concepts. However, rather than specifying that a senior-level partner be responsible for independence matters, the standard takes a more functional approach, requiring a person with the experience, competence, authority, and time needed to enable that person to carry out the assigned responsibilities.

Another key difference, as discussed above, is that QC 1000 imposes specific responsibilities on the individuals assigned the specific roles, such that enforcement action could be brought against them individually if they fail to meet those responsibilities.

The Firm's Risk Assessment Process

The risk assessment process is the basis for a risk-based approach to the design, implementation, and operation of the firm's QC system. The firm's risk assessment process, in combination with the monitoring and remediation process, creates a feedback loop to drive continuous improvement of the firm's QC system.

The proposal included a risk assessment process that would be principles-based and could be tailored to the size and complexity of the firm and the types and variety of engagements it performs. Several commenters, including firms, were generally supportive of a risk-based approach to the firm's QC system. One commenter, an investor-related group, expressed concern that a principles-based approach would allow audit firms too much discretion in conducting their own risk assessment. Another commenter noted that while they generally supported a risk-based, scalable approach, they supported a more prescriptive approach for the resources and monitoring and remediation components.

The Board has retained the approach as proposed because it believes that applying a risk-based approach to the design, implementation, and operation of the QC system will prompt firms to identify and focus on the most relevant risks to quality in the context of their own practice and will make QC 1000 appropriately adaptable to future changes in technology, regulation, and the business environment. It will also ensure scalability, allowing firms to right-size their QC systems as their practices grow and change. As discussed above, QC 1000 contains a balance of prescriptive and risk-based elements.

One commenter requested clarity on whether QC 1000 would operate separately or in concert with other quality control standards, specifically whether the risk assessment process would apply only to engagements performed under PCAOB standards or to the firm's overall risk assessment of all its engagements, including those performed under other standards. Consistent with the way the term "engagement" is defined in QC 1000,¹⁵⁸ the requirements of QC 1000, including those regarding the firm's risk assessment process, generally apply only to work performed under PCAOB standards. However, nothing prevents a firm from designing, implementing, and operating a single risk assessment process for its entire audit and assurance practice that satisfies both QC 1000 and the other quality control standards that apply to the firm.

The risk assessment process should be familiar to firms because it is analogous to existing auditor responsibilities for identifying, assessing, and responding to risks of material misstatement of the financial statements. Audit procedures for identifying and assessing risks of material misstatement include information-gathering procedures to identify risks (e.g., obtaining an understanding of the company, its environment, and its internal control), assessment of risks based on information obtained, and design and implementation of responses to address the identified risks.¹⁵⁹ The standard creates analogous responsibilities in relation to the QC system. Similarly, as the auditor is required by auditing standards to modify the overall audit strategy and the audit plan if circumstances change during the course of the audit,¹⁶⁰ the firm is required by QC 1000 to monitor, identify, assess, and respond to changes in relevant conditions, events, and activities that affect the firm's QC system.

1. QC 1000.18

The firm's risk assessment process applies to the six components of the firm's QC system that specify quality objectives. To design, implement, and operate this process, the firm is required to:

- Establish quality objectives;
- Identify and assess quality risks to the achievement of the quality objectives; and

¹⁵⁸ See Terminology discussed above.

¹⁵⁹ See generally AS 2110, *Identifying and Assessing Risks of Material Misstatement*.

¹⁶⁰ See AS 2110.74.

- Design and implement quality responses to address the identified quality risks.

The process for establishing quality objectives, identifying, and assessing quality risks, and designing and implementing quality responses is iterative, and the requirements of the standard would not necessarily be addressed in a linear manner. For example, in identifying and assessing quality risks, the firm may determine that one or more additional quality objectives are required; in designing and implementing quality responses, the firm may identify additional quality risks. The risk assessment process is also iterative and ongoing, so that new or developing risks are identified and addressed as they emerge. For smaller and less complex firms, the risk assessment process may be centralized and involve only a few individuals. For larger and more complex firms, the risk assessment process may be more structured and decentralized, involving multiple layers and groups. The Board believes that the risk assessment approach will prompt firms to proactively identify, assess, and respond to quality risks, while at the same time allowing them to apply judgment when identifying and assessing quality risks.

a. Establish Quality Objectives (QC 1000.19)

The standard defines quality objectives as the desired outcomes in relation to the components of the QC system to be achieved by the firm. Establishing quality objectives is the first step in the risk assessment process and forms the basis for the identification and assessment of quality risks and the design and implementation of quality responses. The quality objectives are outcome-based and the risk assessment process provides firms the ability to determine how the quality objectives are to be achieved.

One investor-related group expressed concern with the lack of specificity in the proposed standard regarding the design of an audit firm's quality control system, suggesting that the proposed standard would enable firms to design a QC system that could too easily be certified as working properly. The Board believes that the quality objectives specified in QC 1000 will promote an appropriate level of rigor in the QC system. While QC 1000 provides some flexibility with regard to the quality risks that firms identify and the quality responses that firms develop to address those risks, it does not provide the same flexibility with regard to quality objectives. Instead, quality objectives that will apply to all firms are specified

in the standard. Firms can establish additional quality objectives—indeed, they are required to do so if necessary to achieve the reasonable assurance objective—but they generally cannot omit or modify any of the quality objectives set out in the standard. Therefore, firms do not determine the criteria by which their QC systems will be assessed, only the means by which they will meet those criteria.

Quality objectives are specified in the standard for six of the components of the QC system: governance and leadership, ethics and independence, acceptance and continuance of engagements, engagement performance, resources, and information and communication. A firm may determine that it is necessary to establish quality objectives for its monitoring and remediation process. In those circumstances, the firm's risk assessment process would also apply to the monitoring and remediation process. Otherwise, although monitoring and remediation would not be subject to the firm's risk assessment process as described in the standard, it would nevertheless be carried out in a way that is informed by and responsive to quality risks.¹⁶¹

The Board believes that, for many firms, the quality objectives specified in the standard are likely to be comprehensive and it does not expect, in the current environment, that additional quality objectives would generally be necessary. However, the Board also recognizes that the nature and circumstances of a firm and its engagements will vary and conditions may change. Accordingly, a firm is required to establish additional quality objectives if necessary to achieve the reasonable assurance objective.

The requirement for the firm to establish quality objectives necessary to achieve the reasonable assurance objective is designed to prompt ongoing reexamination of the quality objectives and modification as needed, which should enable the firm's QC system to adapt to a changing environment and remain fit for purpose. If a firm determines that its quality objectives need to be more specific, it could establish sub-objectives to provide a more direct link to quality risks and support the development of more comprehensive or better-targeted responses.

¹⁶¹ See Monitoring and Remediation Process below. For example, quality risks and the reasons for their assessment are factors a firm would take into account when determining the nature, timing, and extent of its monitoring activities.

b. Identify and Assess Quality Risks (QC 1000.20)

The proposal defined quality risks as risks that, individually or in combination with other risks, have a reasonable possibility of adversely affecting the firm's achievement of one or more quality objectives if the risks were to occur, and are either (i) risks that have a reasonable possibility of occurring or (ii) risks of intentional acts by firm personnel and other participants to deceive or to violate applicable professional and legal requirements. The "reasonable possibility" term in the definition of quality risks is aligned with use of the term in PCAOB standards:¹⁶² there is a reasonable possibility of an event when the likelihood of the event is either "reasonably possible" or "probable," as those terms are used in the FASB Accounting Standards Codification ("FASB ASC") Topic 450, *Contingencies*.¹⁶³

A number of commenters raised questions or made suggestions about the proposed treatment of intentional acts in the definition of quality risks. One commenter suggested that intentional misconduct should not be explicitly addressed in the definition because the necessary response, especially as it relates to colleagues' behavior, may negatively impact the trust among colleagues and could constrain the achievement of quality objectives. Instead, this commenter suggested that the risk of intentional misconduct may be more effectively considered and responded to as part of the broader understanding of quality risks. Another firm expressed concern that requiring consideration of all illegal acts would contradict a risk-based approach.

Several firms agreed that the definition of quality risks should explicitly address the risk of intentional misconduct but suggested that the definition should also address the possibility of occurrence related to acts of intentional misconduct. Several commenters, including firms, firm-related groups, and an academic, recommended that the threshold of "reasonable possibility of occurring" should apply to all quality risks, including risks of intentional misconduct. Many of these commenters said that not applying the threshold of "reasonable possibility of occurring" to

¹⁶² See generally, e.g., AS 1105, *Audit Evidence*; AS 2101; AS 2201, *An Audit of Internal Control Over Financial Reporting That Is Integrated with An Audit of Financial Statements*.

¹⁶³ See FASB ASC paragraph 450-20-25-1; see also, e.g., footnote 4 to AS 1105.12, which incorporates the ASC definition.

the risk of intentional misconduct would not be practical and could harm audit quality as this would divert time, resources, and attention from addressing more reasonably possible risks. Some commenters referenced the inclusion of the “reasonable possibility of occurring” threshold in AS 2110 and suggested that the same principle should apply to the risk of intentional misconduct in QC 1000. Two of these commenters suggested that not applying the threshold of “reasonable possibility of occurring” to the definition of quality risks would be inconsistent with AS 2401, *Consideration of Fraud in a Financial Statement Audit*, and could impose a threshold on firms that exceeds the current auditing standards over auditors’ identification and assessment of fraud risks. Several commenters also stated that the inclusion of other participants in addressing every conceivable risk of intentional misconduct may be impractical as firms may have limited access to information on the conduct of other participants. One firm suggested that additional guidance may be beneficial with regard to assessing and responding to risks of intentional misconduct by other participants that are not part of the firm.

A firm-related group suggested that not applying the threshold of “reasonable possibility of occurring” to intentional misconduct appeared to go beyond the reasonable assurance objective and expressed concern that, without further clarification of how firms should deal with risks of intentional misconduct with less than a reasonable possibility of occurring, a disproportionate level of resources could be allocated to this area, to the detriment of other quality risks with more than a remote possibility of occurring.

After considering the comments received, the Board revised the definition of quality risks such that the threshold of “reasonable possibility of occurring” applies to all risks, including risks of intentional misconduct by firm personnel and other participants. However, the Board continues to believe that firms should be explicitly prompted to consider risks of intentional misconduct in their risk assessment process, because without such a prompt, firms may discount the possibility that intentional misconduct may occur and omit or underweight these types of risks in their risk assessment process. Therefore, the final definition provides that, for all risks, whether or not related to intentional misconduct, the firm would assess the possibility of occurrence and the possibility that the

risks would have an adverse effect on the achievement of its quality objectives.

One firm suggested that while the threshold of “adversely affecting” is reasonably understood, additional guidance or examples would be welcomed. Another commenter noted that more examples serve as helpful interpretive guidance to those implementing the standard. Two firms believed the threshold is sufficiently clear and did not have specific requests for further guidance. The Board will monitor the implementation of the new standard by audit firms, and, if appropriate, consider the need for additional guidance.

The standard requires the firm to identify and assess quality risks for each quality objective it establishes. Most quality objectives are likely to have multiple quality risks. Some quality risks may relate to multiple quality objectives, either within a single component or across several components. The nature and extent of the firm’s risk assessment process would be commensurate with the firm’s quality risks and therefore will vary across firms in nature, scope, and complexity. In assessing risks, the firm would consider how often the quality risks may occur and the magnitude of the impact of the quality risks on the related quality objectives. The firm would then take this information into account in determining the nature, timing, and extent of the quality response(s) needed to address the quality risk.

One commenter requested clarification of whether the Board expects firms to categorize the identified risks (for example as lower, higher, or significant). While there is nothing in QC 1000 that requires such categorization, firms that find such an approach helpful could certainly use it.

The standard requires the identification and assessment of quality risks annually. Requiring an assessment annually, as well as when matters come to the firm’s attention, drives a systematic, disciplined, and proactive approach to assessing the firm’s quality risks. Through the Board’s oversight activities, it has observed that many firms update their QC systems on an ad hoc basis, in response to changes in regulatory requirements or deficiencies identified by internal or external inspections, and do not have a systematic process of risk assessment. This reactive approach can result in firms taking corrective actions only after deficient audits have been identified. The annual identification and assessment requirement will instill a

regular and disciplined approach to performing the risk assessment process and to identifying new quality risks that require modifications to the firm’s quality responses or quality risks identified in a prior year that may no longer be sufficient or relevant.

The standard does not specify quality risks that must be assessed and responded to by all firms; rather it includes factors for the firm to consider in its risk assessment process. The Board believes that such an approach would result in the firm identifying and assessing the quality risks that are most relevant in light of its facts and circumstances.

i. Obtain an Understanding of the Conditions, Events, and Activities That May Adversely Affect the Achievement of the Firm’s Quality Objectives

The standard requires the firm, as part of identifying and assessing quality risks, to obtain an understanding of the conditions, events, and activities that may adversely affect the achievement of the firm’s quality objectives. This understanding underpins the firm’s identification and assessment of the quality risks that are most relevant to the achievement of the firm’s quality objectives. Appendix B of the standard provides examples related to the nature and circumstances of the firm and its engagements that may give rise to quality risks.

The considerations highlighted in paragraph .20a. and Appendix B could assist the firm in identifying one or more quality risks to the achievement of one or more quality objectives. For example, consideration of changes in a firm’s structure may be relevant for a firm that has recently completed an acquisition of another firm. This consideration may result in the identification of a number of quality risks, such as a quality risk that the audit methodology used by the acquired firm may not be compatible with the acquirer’s methodology or a quality risk that the firm is unable to retain personnel post-acquisition, which may pose risks to quality objectives in areas like engagement performance and resources.

Several commenters, including firms, noted that the examples provided in Appendix B were helpful. Two commenters expressed concern with the language used in paragraph .20a., specifically, that it was not sufficiently clear that the specific examples in Appendix B are meant to be illustrative rather than a checklist for every firm to consider. As the Board stated in connection with the proposal, the list in paragraph .20a. is not intended to be

exhaustive and the specific examples provided in Appendix B are meant to be illustrative rather than a checklist for every firm to consider. Whether particular conditions, events, and activities are relevant, and result in one or more quality risks, depends upon the nature and circumstances of the firm and its engagements and how the conditions, events, and activities relate to or affect the operation of the firm's QC system and the performance of its engagements. The firm may also identify quality risks that do not relate to the list in paragraph .20a. or to any of the specific examples.

One firm expressed concern with the inclusion of proposed paragraph B10b. in Appendix B, which discusses the extent of alignment of a third-party provider's standards of conduct with those of the firm. The firm suggested that the example may imply that third-party providers from outside the public accounting profession may not be appropriate or sufficient, because they may not be subject to a centrally governed code of conduct. Nothing in the Board's standards requires a third-party provider to have a centrally governed code of conduct and the Board has added the phrase "if any" to the example to eliminate any ambiguity in that regard. However, the Board does believe that the existence of such a code of conduct, and the extent to which it aligns with the firm's own standards of conduct, is a relevant example that could be considered by a firm in assessing whether there exist conditions, events, or activities, as a result of its use of resources or services obtained from third-party providers, that may adversely affect the achievement of its quality objectives.

(1) The Nature and Circumstances of the Firm

The standard includes a list of considerations related to the nature and circumstances of the firm. Appendix B of the standard provides specific examples of each consideration in paragraphs .B2 through .B11.

The Board continues to believe that to consistently execute quality audits, it is important that a commitment to audit quality is embedded in the firm's culture and exists throughout the firm. In connection with this, the Board has added a new paragraph .20a.(1)(d) and paragraph .B5 to provide firms with an additional risk assessment consideration relating to the culture of the firm, and the extent to which a culture of integrity and a commitment to audit quality, including ethics and independence, is promoted within the firm and embraced

by firm personnel across all levels of the firm.

In addition, the Board has added paragraph .B6e. to highlight that in understanding the resources of the firm, the firm may also have to consider the risks associated with technological resources, including their susceptibility to cybersecurity breaches.

(2) The Nature and Circumstances of The Firm's Engagements

In obtaining an understanding of the nature and circumstances of the firm's engagements, the firm considers the types of engagements performed by the firm as well as the types of entities for which such engagements are undertaken. Paragraph .B12 of Appendix B of the standard contains a list of examples of these considerations. For instance, a firm that conducts audits of broker-dealers may consider information from relevant authorities, like the SEC and Financial Industry Regulatory Authority ("FINRA"), in identifying risks associated with such audit engagements. The Board added an example to paragraph .B12a. to highlight that in understanding the nature and circumstances of the firm's engagements, the firm may also consider the laws and regulations to which the companies it audits are subject.

(3) Other Relevant Information

Other relevant information captures other information sources that help the firm to identify quality risks. One such source is the firm's monitoring and remediation activities. Consideration of information from those activities creates a feedback loop within the QC system by informing the firm of the results of the monitoring and remediation process that may help the firm identify quality risks.

Other sources are external inspections and oversight activities by regulators, and other external reviews, such as peer reviews. For example, the results of an external inspection may identify a high rate of noncompliance with independence requirements within a specific office of the firm or within a certain employee staff level, which the firm would take into account when identifying and assessing quality risks for the ethics and independence component.

ii. Identify and Assess Quality Risks Based on the Understanding Obtained

Under the standard, identifying and assessing quality risks is an ongoing, iterative process. The firm assesses risks as part of the initial design and implementation of the QC system, and thereafter annually, including in

response to new information or changes in its circumstances and environment.

The standard requires the firm to identify and assess quality risks for each of the quality objectives established by the firm, based on the understanding of the relevant factors and other relevant information and taking into account whether, how, and the degree to which the achievement of the quality objectives may be adversely affected. The note clarifies that this assessment is based on inherent risk, without regard to the effect of any related quality responses. The assessment is similar to the determination made under AS 2201 as to whether an account or disclosure is significant based on inherent risk, without regard to the effect of controls.¹⁶⁴ One commenter agreed with the clarification provided in the note that the assessment is based on inherent risk, but expressed concern that the note may not be sufficient to prompt or remind auditors of the independence of quality risks from quality responses. The Board believes that the note to paragraph .20b. provides clear direction for assessing quality risks without regard to the effect of quality responses. The Board will monitor the implementation of the new QC standard, and, if appropriate, consider the need for additional guidance. Quality risks may affect one or more quality objectives, either within a single component or across several components. For example, a quality risk that the firm may not be able to attract and retain qualified personnel would affect several quality objectives in the resources component, and may also affect quality objectives in other components, such as engagement performance or engagement acceptance and continuance.

Under the definition of quality risks, the firm would not be required to identify every conceivable risk, but only those that have a reasonable possibility of occurring and, if they were to occur, a reasonable possibility of adversely affecting the firm's achievement of one or more quality objectives. The identification of quality risks takes into account individual risks as well as combinations of risks. For example, a risk that has a reasonable possibility of occurring but individually does not have a reasonable possibility of adversely affecting the achievement of the quality objective may meet the proposed definition of a quality risk when analyzed in combination with other risks.

The firm may undertake the quality risk assessment separately or

¹⁶⁴ See AS 2201.A10.

concurrently with risk identification. Assessing the identified quality risks involves consideration of the frequency with which the quality risks may occur and the magnitude of the impact of the quality risks on the related quality objective(s). Identifying quality risks with the appropriate degree of specificity (not too narrowly or too

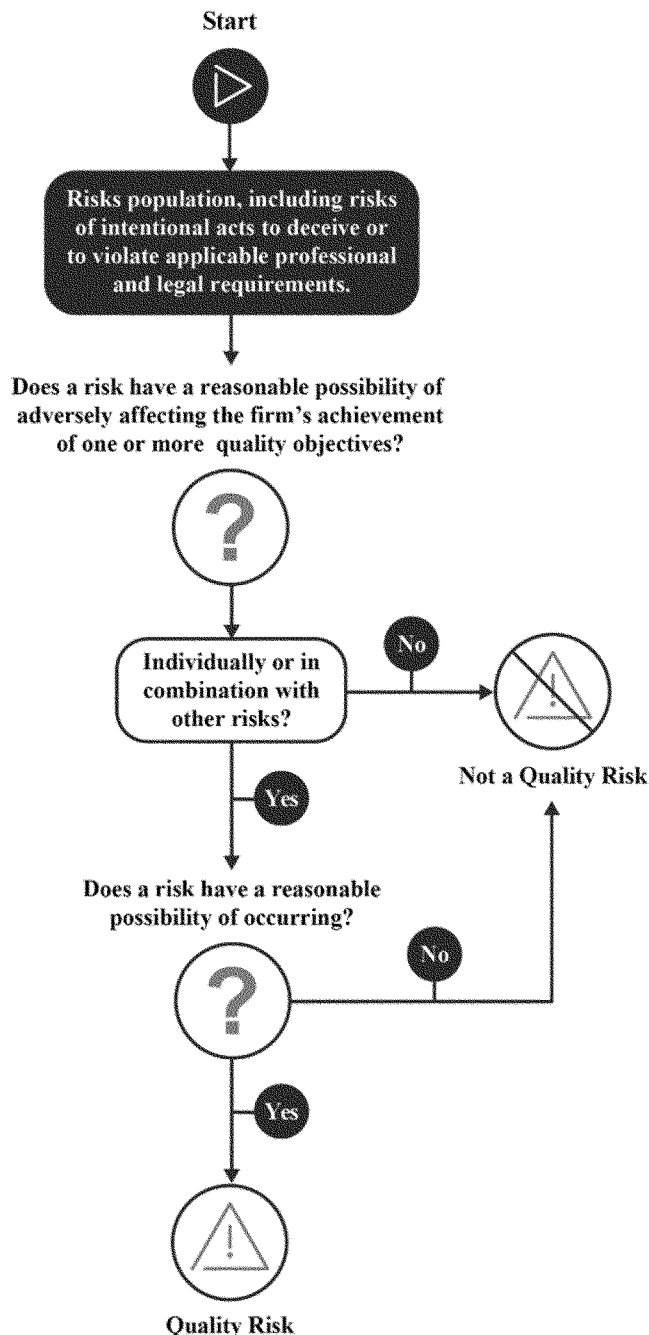
broadly) would help the firm design quality responses that reduce to an appropriately low level the risk that the quality objective will not be achieved. Quality risks that are defined too broadly may result in quality responses that are not sufficiently targeted to the actual quality risk. Conversely, if quality risks are defined too narrowly, the

quality responses may not sufficiently address the full extent of the actual quality risk.

The process of identifying and assessing quality risks is depicted below.

BILLING CODE 8011-01-P

Identifying and Assessing Quality Risks



BILLING CODE 8011-01-C

c. Design and Implement Quality Responses (QC 1000.21)

The standard requires the firm to design and implement quality responses that address quality risks in order to achieve the quality objectives. Quality responses are defined as policies and procedures designed and implemented by the firm to address quality risks. Under the definition, policies are statements of what should, or should not, be done to address assessed quality risks. Procedures are actions to implement and comply with policies.

Under the principles-based approach of the standard, the nature, timing, and extent of quality responses depend on the underlying quality risks and the reasons why these risks were assessed as quality risks. For example, a quality risk that is tied to an event that is expected to occur multiple times per year, or that could have a very significant impact, requires a more extensive response than a quality risk tied to a specific event that is expected to occur only once and have a less significant impact.

The firm may decide to implement quality responses at the firm level or the engagement level, or through a combination of responses at the firm and engagement levels, depending on the nature of the quality risk. Quality responses may address multiple quality risks related to one or more QC components.

Quality responses may vary depending on to whom they apply. For example, based on the quality risks that are being addressed, the firm may develop some policies and procedures that are applicable to all firm personnel and others that apply only to firm leadership or personnel in a particular function or geographic location. Similarly, the firm's policies and procedures regarding other participants may be different for different types of other participants (e.g., network affiliates, engaged specialists).

Information obtained from the identification and assessment of quality risks enables the firm to develop quality responses that appropriately and adequately respond to the quality risks. In assessing risks, the firm would consider how often the quality risks may occur and the magnitude of the impact of the quality risks on the related quality objectives. The firm would then take this information into account in determining the nature, timing, and extent of the quality response(s) needed to address the quality risk.

In addition to the quality responses designed by the firm, the standard

requires certain specified quality responses for all firms. Some specified quality responses are drawn from existing PCAOB requirements¹⁶⁵ or from the specified responses in ISQM 1,¹⁶⁶ and have been included either to carry existing requirements into the new standard or to create other obligations that would have to be met in designing, implementing, and operating the QC system. Other specified quality responses are new provisions that the Board believes are sufficiently important to merit an explicit requirement. The specified quality responses are not intended to be comprehensive; on the contrary, for most of the components of the firm's QC system, QC 1000 includes only a few specified quality responses, and for the engagement performance component there are none. As a result, the specified quality responses alone would not be sufficient to enable the firm to achieve all established quality objectives, and firms must design and implement their own quality responses in addition to the specified quality responses. The specified quality responses and the quality responses the firm designs and implements on its own are critical in addressing quality risks.

For example, the specified quality response requiring mandatory training¹⁶⁷ may address some of the quality risks related to certain quality objectives in the resources component (e.g., hiring, developing, and retaining firm personnel).¹⁶⁸ However, mandatory training alone will not be sufficient to address all the quality risks that may be identified for that quality objective and will have to be combined with additional firm-developed quality responses.

d. Modifications to the Quality Objectives, Quality Risks, or Quality Responses (QC 1000.22–.23)

The standard requires firms to take proactive measures to address new quality risks that may come up between the firm's periodic risk assessments. To the extent practical, these policies and procedures would be not just retrospective, but also forward-looking, so the firm could anticipate and plan for significant changes. For example, a new accounting standard may result in a firm identifying a new quality risk that firm personnel may misinterpret the new standard. Identifying this risk prior to the next annual risk assessment may prompt the firm to revisit its quality

responses that are affected by this event, and thus avoid potential problems in future engagements.

One commenter suggested that it may be cost beneficial to require or encourage audit firms' QC leaders to stay current with developments in auditing literature to put them in a better position to triage newly identified quality risks and identify engagements susceptible to those risks. Another commenter recommended that firms be required to create an individual or other entity charged with maintaining situational awareness.

The Board notes that paragraph .22 of QC 1000 requires firms to establish policies and procedures for monitoring changes to conditions, events, and activities that indicate modifications to the firm's quality objectives, quality risks, or quality responses may be needed. In addition, the individual(s) responsible for monitoring such changes are subject to the general due professional care standard of QC 1000.10, which requires a critical assessment of the relevant information (which would include relevant literature). In light of these overarching requirements, the Board does not consider it necessary to add the specific provisions that commenters suggested. Rather, the Board believes that allowing flexibility for firms to establish policies and procedures to monitor, identify, and assess changes to conditions, events, and activities encourages firms to concentrate their efforts on the risks most relevant to them and contributes to the standard being appropriately scalable. A firm may of course determine, based on its nature and circumstances, that it is appropriate to establish specific policies and procedures for the monitoring of developments in auditing literature or to charge a specific individual with maintaining situational awareness.

Policies and procedures in this area may vary, depending on the size and complexity of the firm and the types and variety of engagements it performs. For a larger firm operating in a complex environment and auditing a wide range of different types of companies, such policies and procedures would be extensive. For example, they could involve periodic meetings with teams across the firm to gather and analyze the necessary information to enable the firm to identify changes to conditions, events, and activities that may require modification of the firm's quality objectives, quality risks, or quality responses. Smaller and less complex firms, operating in a less varied and more stable environment, may have a

¹⁶⁵ See, e.g., QC 20.10, .13a, .13b, and .15a.

¹⁶⁶ See paragraph .34 of ISQM 1.

¹⁶⁷ See QC 1000.48.

¹⁶⁸ See QC 1000.44a.

less extensive set of policies and procedures.

If the firm identifies changes to conditions, events, or activities indicating modifications to the quality objectives, quality risks, or quality responses may be needed, the standard requires the firm to determine what, if any, modifications are needed, and to make them on a timely basis. The timing depends on the nature and extent of the modification needed. In some circumstances, immediate action may be required, whereas in other cases, if the impact on risk is less urgent, immediate action is not necessary. Modifications not implemented in a timely manner may fail to prevent quality risks from occurring and adversely affecting the quality objective. For example, in the case of a new accounting standard, the firm would need to implement any necessary modifications to its quality responses in time so that, once the standard became effective, firm personnel would be able to apply it properly.

2. Current PCAOB Standards

Under current PCAOB QC standards, firms have a responsibility to establish and maintain a QC system to provide the firm with reasonable assurance that its personnel comply with applicable professional standards and the firm's standards of quality. The current QC standards make few explicit statements about risk assessment.¹⁶⁹

Governance and Leadership

The governance and leadership component of the firm's QC system addresses the environment that enables the effective operation of the QC system and directs the firm's culture, decision-making processes, organizational structure, and leadership. A firm's culture and tone, as set by leadership, can and should promote the importance of quality.

The PCAOB has long considered firm governance and leadership to be an important aspect of firms' QC systems. For example, PCAOB inspections have historically covered the firm's tone at the top, a foundational aspect of governance and leadership, during the process for reviewing firms' QC systems.¹⁷⁰ PCAOB inspection

procedures focus on how firm management is structured and whether actions and communications by the firm's leadership—the tone at the top—demonstrates a commitment to audit quality.¹⁷¹

1. QC 1000

a. Governance and Leadership Quality Objectives (QC 1000.24)

Under QC 1000, a firm is required to establish quality objectives for the governance and leadership component in several different areas:

- The firm's commitment to quality;
- Organization and governance structure; and
- Resources.

i. The Firm's Commitment to Quality (QC 1000.25.a–d)

The firm's commitment to quality is an important factor in influencing the behavior of firm personnel and the conduct of engagements. The Board believes that the firm's commitment to quality is most effectively demonstrated through the communications, actions, behaviors, and directives of leadership at all levels of the firm. Accordingly, the quality objectives related to commitment to quality are directed at the communications, actions, and accountability of firm leadership.

Frequent and consistent communication from leadership to firm personnel regarding the commitment to quality is important in order to create an appropriate culture and tone at the top. Paragraph .25a. focuses on communicating and promoting key professional attributes by recognizing and reinforcing the firm's role in protecting the interests of investors and the public interest by meeting the firm's responsibilities; the importance of adhering to appropriate standards of conduct; the importance of professional ethics, values, and attitudes; and expected behavior and responsibility of firm personnel for quality both in QC-related activities and the performance of engagements. Collectively, these attributes and expected behaviors are the foundation of an effective QC system.

To achieve an appropriate tone at the top, however, it is not enough for firm

leadership to “talk the talk.” They also have to “walk the walk.” Accordingly, paragraphs .25b. and .25c. establish objectives with regard to leadership's responsibility for and commitment to quality, including through leadership's own behavior. For example, leadership would demonstrate a commitment to quality by acting in a manner consistent with the firm's communications described in paragraph .25a. regarding expectations of firm personnel. Conversely, repeated failure to take steps to address known quality concerns would demonstrate a lack of commitment to quality.

One commenter sought clarification on the term “leadership,” including whether it relates only to the specified roles in paragraph .11 and .12, or to all partners and equivalents in the firm. Under QC 1000, leadership is not limited only to those in specified QC roles. While the composition of leadership may vary due to the nature and circumstances of the firm and its engagements and how the firm chooses to organize itself, it includes firm-wide leadership; the executive team; regional, office, and industry segment leadership; and any other levels of leadership the firm may establish. Not all partners or partner equivalents are necessarily leadership; it would depend on the role of the individual.

Firms and firm-related groups were broadly supportive of the Board's proposed quality objectives for governance and leadership. However, several commenters, mostly investors and investor-related groups, urged the Board to go further in stressing the role of firm leadership and the QC system as a counterbalance to the economic incentives that may drive firms to compromise on quality. Some suggested that compensation plans should weigh quality as much as, or more than, revenue generation. One investor-related group suggested that the standard should increase accountability for the firm and firm leadership's quality control efforts. Another investor stated that audit quality should be required to be considered at the time of the appointment of firm leadership. One commenter suggested that leadership's accountability should not be limited to deficiencies and outcomes but extended to acknowledge positive behaviors and processes.

After considering these comments, the Board revised paragraph .25b to explicitly mention performance evaluation and compensation in the context of defining leadership's responsibility for quality and holding leadership accountable. The Board believes this will drive increased clarity

¹⁶⁹ See, e.g., QC 20.16 (explaining that a firm's policies and procedures should provide for obtaining an understanding with the client about the services to be performed, to minimize the risk of misunderstandings); QC 30.05 (identifying risks associated with the firm's practice as a consideration in determining the need for and extent of internal inspection procedures in monitoring the firm's QC system).

¹⁷⁰ See, e.g., *Report on the PCAOB's 2004, 2005, 2006, and 2007 Inspections of Domestic Annually*

Inspected Firms, PCAOB Rel. No. 2008–008 (Dec. 5, 2008) at 6, available at https://pcaobus.org/Inspections/Documents/2008_12-5_Release_2008-008.pdf; Staff Inspection Brief, Vol. 2017/3: *Information about 2017 Inspections* (Aug. 2017) at 8, available at <https://pcaobus.org/Inspections/Documents/inspections-brief-2017-3-issuer-scope.pdf>.

¹⁷¹ See <https://pcaobus.org/oversight/inspections/inspection-procedures> for information related to the PCAOB's inspection procedures.

about the scope of leadership's responsibilities and increased accountability for an effective QC system, and will prompt firms to focus on their expectations for leadership behavior and the incentives that drive it. Firms can use a variety of different means to define the responsibility for quality and drive accountability—from firmwide communications and policies to individualized job descriptions, performance targets, promotion criteria, compensation schemes, and sanctions—and can acknowledge both outcome-based and process-based measures and both positive and negative behaviors. The revised quality objective reflects that performance evaluation and compensation play a necessary role in that process.

While the Board agrees with the commenter that quality considerations should be taken into account in the appointment of firm leadership, the Board believes other quality objectives already address that issue, such as paragraph .44g of QC 1000. Additionally, the criteria for appointing firm leadership may appropriately vary based on the size of the firm and the nature of its practice, so the Board has avoided being prescriptive in that regard. For example, a larger firm may have numerous candidates for leadership roles with many criteria considered for appointment, but smaller PCAOB audit practices may have limited personnel eligible for leadership roles.

As noted in the proposal, paragraph .25d, focuses on the firm's commitment to quality in relation to its strategic decisions and actions, which include matters such as the firm's financial goals, growth of the firm's market share, industry specialization, business combinations, new geographic markets, and new service offerings. The quality objective emphasizes that a firm's strategic decisions and actions should be consistent with and support the firm's commitment to quality.

One commenter expressed concern that strategic actions may take extended periods of time to yield benefits to quality, and it may be challenging for firms to demonstrate that such actions are consistent with a commitment to quality. The Board notes, however, that this quality objective does not prescribe any specific time horizon, and the Board believes it is wholly consistent with both short-term measures and long-term investments in technology, training, knowhow, and other means of strengthening a firm's audit practice that may take an extended period to yield measurable improvements.

Some investors and investor-related groups suggested that the Board require a clear separation of duties between those responsible for audit quality and those responsible for commercial interests. Two of those commenters cited the regulation of credit ratings agencies as an example of appropriate separation of regulated activity and commercial interests.¹⁷² Another commenter cited with approval the 2007 amendments to the AICPA QC standard, which included application material to the effect that QC leaders should have the authority to implement policies and procedures to ensure that others within the firm will not override those policies to meet short-term financial goals (a concept that does not appear in other QC standards).¹⁷³

The Board considered mandating a greater degree of separation between decision-making about QC and potential commercial motivations, as these commenters suggested, but the Board does not believe such separation can be achieved by all firms, especially firms with smaller PCAOB audit practices with limited leadership roles. As discussed in more detail below, the Board is requiring firms with larger PCAOB audit practices to include an element of independent oversight of their QC system. Moreover, the Board does not believe it would be appropriate to mandate a fully separate or independent QC function. Potential conflicts of interest at the engagement level are addressed in numerous ways in the Board's regulatory scheme: through independence requirements,¹⁷⁴ ethical requirements of integrity and objectivity,¹⁷⁵ and the basic requirement of professional skepticism, a critical aspect of due professional care.¹⁷⁶ At the firm level, the Board believes that those conflicts can best be addressed by emphasizing the responsibility and accountability of firm leadership. QC 1000 requires that responsibility for QC reside at the highest levels of firm leadership, and that leaders are evaluated and compensated in a way

that creates accountability. In the Board's view, appropriately incentivized firm leadership are best positioned to set the tone and establish a quality-focused culture throughout the firm. Rather than requiring firms to segregate the governance of the firm's audit practice from the firm's other commercial interests, the Board believes the quality objectives described in paragraph .25 will promote responsibility for and commitment to quality, while allowing firms to develop quality responses appropriate to their particular governance structure.

Lastly, one commenter suggested the governance and leadership component should promote diversity, equity, and inclusion in recruiting talented leaders, a governance body, and auditors. Another commenter suggested leadership can demonstrate its commitment to quality through providing ongoing, meaningful support of scholarly audit and accounting research. The Board has not revised the standard to reflect these specific suggestions; however, firms may identify quality risks and design and implement quality responses in these areas to achieve the quality objective in paragraph .25a or other quality objectives established by the firm.

ii. Organizational and Governance Structure (QC 1000.25.e)

Establishing and maintaining appropriate firm organizational structures provides an institutional framework supporting the firm's QC system and the performance of the firm's engagements. Organizational structures may include operating units, operational processes, divisions, and geographical locations.

Firm organizational structures may differ based on the size and complexity of the firm in order to be flexible, scalable, and proportionate to the circumstances of the firm. Some firms may concentrate or centralize processes or activities and other firms may have a decentralized approach. Some firms may use internal shared service centers in the operation of the firm's QC system or to enable the performance of its engagements.

A firm's governance structure may include a governing board or committee with representation from various service lines, or with members who are independent of the firm.¹⁷⁷ Such a

¹⁷² See 17 CFR 240.17g-5(c)(8), pursuant to which ratings agencies are prohibited from having any person who participates in determining or monitoring a credit rating, or developing or approving procedures or methodologies used for determining a credit rating, also participate in sales or marketing or be influenced by sales or marketing considerations.

¹⁷³ See AICPA, QC Section 10, *A Firm's System of Quality Control*, paragraph .A5.

¹⁷⁴ See PCAOB Rule 3500T, *Interim Ethics and Independence Standards*.

¹⁷⁵ See EI 1000, *Integrity and Objectivity*.

¹⁷⁶ The general principles and responsibilities of the auditor when conducting an audit, including professional skepticism and due professional care, are being reaffirmed and combined in AS 1000, as adopted. See Auditor Responsibilities Release.

¹⁷⁷ When the Board refers to independence in the context of firm governance, it means the criteria typically applied to independent directors of issuers. See, e.g., *New York Stock Exchange ("NYSE") Listed Company Manual*, Section 303A.01-.02; Nasdaq Rule 5605(a)(2). This is distinct from the requirements for auditor

governing board may have subcommittees to assist it with managing specific areas, such as strategic planning, resource planning, the firm's risk assessment process, and the monitoring and remediation process.

Paragraph .25e., which did not attract specific comment and the Board adopted as proposed, will drive a firm's organizational and governance structure to enable the design, implementation, and operation of the QC system and support performance of the firm's engagements in accordance with applicable professional and legal requirements. This results-oriented approach focuses on whether the QC system actually works as intended and allows firms to tailor the establishment of their governance structure. Additionally, the firm would consider the complexity and operating characteristics of the firm as part of performing its risk assessment process and identifying quality risks.¹⁷⁸

The assignment of roles, responsibilities, and authority within the firm's organizational structure is a key aspect of the design, implementation, and operation of the QC system. Establishing clear roles and responsibilities and clear lines of authority helps to translate the broad institutional objectives of the QC system into individual actions to be performed and monitored, and for which individuals can be held accountable. The assignment of roles and responsibilities may vary across firms depending on the nature and circumstances of the firm and its engagements.¹⁷⁹ For example, in a smaller firm with a limited number of individuals in leadership roles, the individual with oversight of the firm may assume all of the roles and responsibilities related to the QC system. A larger firm may have multiple levels of leadership that align to the firm's organizational structure.

iii. Resources (QC 1000.25.f)

The firm's resources¹⁸⁰ enable the operation of the firm's QC system and the performance of the firm's engagements. Firm leadership influences the nature and extent of the resources that the firm obtains, develops, uses, and maintains, and how

independence from the audit client, discussed below.

¹⁷⁸ Appendix B includes an example regarding the existence and extent of governance structures providing oversight of leadership. See QC 1000.B2.g.

¹⁷⁹ See Roles and Responsibilities above, for a discussion of specific roles and responsibilities that are required to be assigned.

¹⁸⁰ See Resources below, for a discussion of the different types of resources.

those resources are allocated or assigned, including the timing of when they are used. This quality objective, which did not draw comment and which the Board adopted as proposed, emphasizes the importance of the firm having the necessary resources, and allocating them appropriately, such that the firm's QC system is designed, implemented, and operated effectively and the firm's engagements are performed in accordance with applicable professional and legal requirements.

b. Governance and Leadership Specified Quality Responses (QC 1000.26–29)

The proposal included three specified quality responses in the governance and leadership component, discussed in greater detail below. Some firms and a firm-related group objected generally that the specified quality responses were overly prescriptive and unnecessary, and suggested they should be reformulated as risk-based quality objectives. Other firms generally supported including specified quality responses.

The Board believes the specified quality responses address important risks that justify specific requirements and has retained them in the final standard. Firms are required to include these specified quality responses when designing and implementing quality responses to address the quality risks in the governance and leadership component.

Proposed QC 1000 included a requirement for the firm to establish and maintain clear lines of responsibility and supervision within its QC system. A commenter argued that the quality objective in paragraph .25e is sufficient and the specified quality response was not necessary. While paragraph .27 may address a portion of the firm's quality response to .25e, the Board believes paragraph .27 provides additional direction that is appropriate for all firms. Establishing and maintaining structures within the firm—including defining authorities, responsibilities, accountabilities, and supervisory and reporting lines for roles within the firm—will support the effective design and operation of the QC system and the performance of the firm's engagements, regardless of the size of the firm or the types of engagements it performs. The requirement also complements the documentation requirements of QC 1000.¹⁸¹

¹⁸¹ See QC 1000.82a. for the documentation requirements related to lines of responsibility and supervision.

One commenter expressed concern that this requirement, in combination with the requirements of paragraph .12, could result in a prescriptive, hierarchical approach that would not be desirable or practical. The requirement in the final standard is intended to enhance supervision within the context of firms' existing QC systems and supervisory structures. It does not require firms to develop or adopt any particular supervisory structure and would be compatible with a range of different approaches, including very flat structures.

The commenter also expressed concern that individuals acting in a supervisory capacity could face liability beyond what exists under Sarbanes-Oxley, which may disincentivize teaming. As discussed above, paragraphs .15, .16, and .17 of the final standard prescribe specific supervisory roles within a firm's QC system, and the individuals who fill those roles are supervisory persons who must exercise reasonable supervision for purposes of section 105(c)(6) of Sarbanes-Oxley. Additionally, to the extent that other individuals are assigned supervisory responsibilities in light of paragraph .27's specified quality response, those individuals, like all who are involved in the design, implementation, and operation of the QC system, must exercise due professional care as set forth in paragraph .10 of the final standard.

Another commenter recommended that individuals in supervisory roles should be held liable only for knowing or reckless violations. The Board notes that paragraph .27 does not itself create responsibilities for supervisory personnel or prescribe standards of liability that apply when those responsibilities are not met. Those issues are addressed elsewhere in the PCAOB's standards and rules, including in the roles and responsibilities component of QC 1000 and PCAOB Rule 3502,¹⁸² as well as in section 105(c)(6) of Sarbanes-Oxley.¹⁸³ In the

¹⁸² See PCAOB Rule 3502. The Board has proposed to amend Rule 3502 to change the standard of conduct for associated persons' contributory liability from recklessness to negligence and to provide that an associated person contributing to a violation need not be an associated person of the registered firm that commits the primary violation. See PCAOB Rel. No. 2023–007.

¹⁸³ Under section 105(c)(6) of Sarbanes-Oxley, if an associated person of a registered public accounting firm violates any provision of law, rules, or standards referenced in section 105(c)(6), the Board may impose sanctions on the firm or its supervisory persons if the Board finds that there was a failure reasonably to supervise that associated person with a view to preventing such a violation. The Board has adopted a rule related to section

Board's view, the requirement to establish and maintain clear lines of authority and supervision primarily serves to clarify how the QC system is structured and how it operates, by laying out clearly the authorities, responsibilities, accountabilities, supervisory and reporting lines, and who is responsible for each element of the QC system. If the requirement has consequences in terms of individual accountability and liability, that would only be because it removes any doubt about which individuals are acting in a supervisory capacity and the scope of their respective responsibilities, thereby clarifying how these other provisions should be applied.

The proposal included a specified quality response to incorporate an oversight function for the audit practice including at least one person from outside the firm, which would apply to firms that issue audit reports with respect to more than 100 issuers. *See* Scalability above, for a discussion of the 100-issuer threshold.

Comments were mixed on the need for and potential breadth of this requirement. The Board received several comments, primarily from investors and investor-related groups, suggesting that the proposed requirement did not go far enough. Some commenters stated that the oversight function should not be limited to one individual but instead a larger number (such as three) of independent non-employee members should be required, or potentially an advisory council or committee of the firm's board of directors with multiple or even a majority of independent non-employee members. Some of these commenters asserted that requiring only one person with undefined authority to serve in an oversight role makes it unlikely to be effective and falls short of the 2008 recommendations of the U.S. Treasury Department's Advisory Committee on the Auditing Profession, which suggested consideration of "firms appointing independent members with full voting power to firm boards and/or advisory boards with meaningful

governance responsibilities."¹⁸⁴ One commenter objected that the requirement only mandates practices that are already in place at the largest firms, and so will not generate any change. Another commenter asserted that there is little merit in requiring an independent member of the firm's oversight function without also considering the balance of the oversight function and the contribution of the independent member. Others called for more specificity about the individual's role, including specific powers, such as the power to meet with firm management and obtain relevant information. Some investor-related groups also called for transparency on the role of the non-employee members.

Many commenters, including some larger firms, supported the oversight role. Two commenters suggested that the requirement for an independent oversight function be extended to apply to all firms that issue audit reports for issuers and one of these commenters suggested having firms consider whether an independent function is an appropriate response to achieving the quality objectives.

Other commenters, including some mid-sized firms, did not support the specified quality response and suggested it should be a quality objective instead. One firm suggested that the objective could be better accomplished by designating an "audit quality expert" on a firm's board (similar to a "financial expert" on an audit committee) or by hiring independent external QC advisers. Some commenters expressed concern about the lack of specificity and clarity regarding the role, including questions regarding the individual's authority and function. One noted that the individual was not required to be a CPA and asserted that the need for and benefits of the role had not been sufficiently articulated; on that basis, the commenter did not support it. Another commenter did not see the linkage between the specified quality response and the quality objectives and suggested that the lack of definition of the role, coupled with a lack of clarity about which quality objectives were being addressed, would make implementation challenging. Other commenters stated that finding individuals to fill this role may be challenging.

Some commenters requested guidance on how to implement the requirement, including with respect to the qualifications or roles of the

individuals. One firm sought clarity on whether supervisory liability under Sarbanes-Oxley section 105(c)(6) would apply equally to members with an oversight or advisory function. Some commenters, including firms, expressed concern about the potential scope and meaning of the terms such as "governance structure," "independent judgment," and "oversight function," and requested confirmation that current practices such as independent advisory boards are a permissible approach. One firm requested an extended implementation period to allow time for firms to design and implement the oversight function, including identifying and onboarding appropriate individuals.

Based on the comments received, the Board refined the proposed requirement to provide additional specificity and clarity. The final rule refers to an "external" oversight function "for the QC system composed of one or more persons," none of whom has a disqualifying relationship with the firm. This more precise language clarifies that the focus is on the QC system and emphasizes that the function is to be carried out entirely by one or more persons external to the firm, who are not principals or employees of the firm and do not have any other relationship with the firm that would interfere with the exercise of independent judgment with regard to QC-related matters. The Board also added a name for the position—External QC Function, or EQCF—which it believes clarifies and underscores that the person or persons are external to the firm and serve in a QC-focused role.¹⁸⁵ The Board also conformed the provision to the descriptions in QC 1000.12 of other specified QC system roles by providing that the EQCF should have the experience, competence, authority, and time necessary to enable them to carry out the responsibilities assigned to them by the firm.

To clarify what is entailed in "an external oversight function for the QC system," the final standard also specifies a baseline requirement that the EQCF's responsibilities should include evaluating, at a minimum, the significant judgments made and the related conclusions reached by the firm when evaluating and reporting on the effectiveness of its QC system. The Board believes this addition is responsive to commenters who requested clarification of the proposal, as well as those suggesting that the

105(c)(6) that provides for commencing a disciplinary proceeding if it appears that a firm or its supervisory personnel have failed reasonably to supervise an associated person who has committed a violation. *See* PCAOB Rule 5200, *Commencement of Disciplinary Proceedings*, at (a)(2); *see also, e.g., In the Matter of Scott Marcello, CPA*, PCAOB Rel. No. 105–2022–004 (Apr. 5, 2022) (imposing sanctions under section 105(c)(6)); *In the Matter of WWC, P.C.*, PCAOB Rel. No. 105–2022–006 (Apr. 19, 2022) (same); *In the Matter of KPMG Inc., Cornelis Van Niekerk, and Coenraad Basson*, PCAOB Rel. No. 105–2022–015 (Aug. 29, 2022) (same).

¹⁸⁴ U.S. Treasury Department, *Advisory Committee on the Auditing Profession Final Report* (Oct. 6, 2008) at VII.8.

¹⁸⁵ Firms may assign other functions to the person or persons serving in the EQCF role so long as the specified QC function can be carried out as set forth in the standard and discussed in this release.

standard include some specific requirements with respect to the role. The Board expects that firms will make a number of significant judgments in performing and reporting on their QC system evaluation. The Board expects that the person or persons serving in this external oversight function will evaluate judgments made by firm personnel in the firm's evaluation of the firm QC system and the required reporting.

The evaluation performed by the EQCF will be in some respects analogous to the EQR's evaluation of significant judgments made by the engagement team and the related conclusions reached in forming the overall conclusion on the engagement and in preparing the engagement report.¹⁸⁶ Like the EQR, the EQCF will review and evaluate work performed by others, not redo the work, and must exercise due professional care in performing their responsibilities.¹⁸⁷

However, there are important differences between the requirements for the EQR and the EQCF. Unlike the EQR standard, QC 1000 does not impose specific limits on the length of service of the EQCF, though firms should consider the potential for arrangements relating to length of service, such as term limits and protections against removal, to prevent the creation of a relationship with the firm that impairs independent judgment. QC 1000 also does not specify the procedures the EQCF should perform to evaluate the significant judgments made and related conclusions reached. These may vary based on the circumstances of the firm and the design, implementation, and operation of its QC system, but must be sufficient to enable the EQCF to perform their evaluation with due professional care. In addition, unlike the EQR standard, QC 1000 does not require that the EQCF provide concurring approval of reporting, although firms would be free to establish such concurring approval as a matter of policy. Documentation will have to be prepared and maintained in sufficient detail to evidence how the quality response operated.¹⁸⁸ This will form part of the QC documentation supporting the firm's ongoing risk assessment and monitoring and remediation efforts, as well as the Board's oversight activities. Under QC

1000.65, firms will be required to consider the EQCF's evaluation in their ongoing monitoring of the QC system (including monitoring of the evaluation process).

Separately, the Board carefully considered commenter suggestions to increase the required number of independent individuals and to establish specific eligibility criteria for them. Given the oversight responsibility of an EQCF, the Board believes at least one person is always necessary and firms may determine, based on their circumstances, that more than one person is needed to appropriately carry out the function. The Board believes the requirement will respond to the quality objective in paragraph .25e by ensuring an independent perspective on QC matters, but it does not supplant firm leadership or relieve them of their fundamental responsibility to instill and maintain a firm culture that appropriately prioritizes QC.

Accordingly, the Board does not believe it would be appropriate to mandate a specific number of individuals or the specific credentials they must have (besides their ability to exercise independent judgment with regard to matters related to the QC system and the general requirement that they have the experience, competence, authority, and time necessary to enable them to carry out their assigned responsibilities). Rather, the decision will be based on specific skillsets of the person or persons in this function to be able to carry out the requirements of the function. In that regard, firms may conclude that one or persons appointed to the EQCF should be non-auditors to bring a greater diversity of perspectives to the function.

Beyond the minimum responsibilities specified in the standard, the Board gave firms flexibility in establishing other responsibilities of the EQCF, enabling the function to best respond to the nature and circumstances of the firm. For example, if the firm has experienced an increase in recurring engagement deficiencies, the firm may charge the EQCF with reviewing and evaluating the firm's remediation actions and monitoring plan. As another example, a firm may assign the EQCF with strategic responsibilities, such as maintaining situational awareness through the identification and monitoring of emerging risks or trends that could potentially affect the firm's QC system. While QC 1000 specifies that the EQCF exercise oversight over the QC system, the firm may also choose to extend its authority more broadly. The responsibilities assigned to the EQCF will in turn drive decisions about

the scope of the EQCF's authority. At a minimum, that will entail sufficient access to information, documentation, and firm personnel to enable evaluation of the significant judgments made and the related conclusions reached by the firm when evaluating and reporting on the effectiveness of its QC system, but it could be broader depending on the scope of the EQCF's responsibilities as assigned by the firm.¹⁸⁹ Consideration of the experience, competence, and time necessary to serve in the role will likewise depend on the responsibilities assigned by the firm.

The firm may consider many matters when establishing an EQCF. Such matters could include:

- The responsibilities assigned by the firm to the EQCF, including those specified in QC 1000;
- The qualifications required of the individual(s) assigned to fulfill those responsibilities, including those specified in QC 1000;
- The scope of authority afforded to the EQCF in light of the assigned responsibilities;
- Whether to establish a direct line of communication from the EQCF to the individual assigned ultimate responsibility and accountability for the QC system as a whole, or the individual assigned operational responsibility for the QC system as a whole, or both;
- Whether to require that the EQCF comply with independence requirements applicable to auditors;¹⁹⁰
- The level of external transparency of the EQCF's role and responsibilities;
- The compensation structure for the EQCF; and
- The term of service for the EQCF, including restrictions on removal and limits on length of service.

In making these determinations, the firm should be mindful of the requirement that members of the EQCF not have any relationship with the firm that would interfere with the exercise of independent judgment with regard to matters related to the QC system.

The EQCF could be, but would not be required to be, in the "chain of command" under the SEC independence rule.¹⁹¹ The Board does not believe that the EQCF would be a "supervisory person" under Sarbanes-Oxley section 105(c)(6) solely by virtue

¹⁸⁹ The scope of the firm policies and procedures regarding the EQCF will also depend on its role and the associated risks. For example, pursuant to QC 1000.53g, firms will have to develop policies and procedures regarding information communicated to and obtained from the EQCF.

¹⁹⁰ See Regulation S-X Rule 2-01(b)-(c), 17 CFR 210.2-01(b)-(c), and PCAOB Rules under Section 3, *Auditing and Related Professional Practice Standards*, Part 5—*Ethics and Independence*.

¹⁹¹ See 17 CFR 210.2-01(f)(8).

¹⁸⁶ See AS 1220.09.

¹⁸⁷ See QC 1000.10; AS 1220.12.

¹⁸⁸ QC 1000.83b. The board expects such documentation to include both (1) how the EQCF evaluated the significant judgments made and the related conclusions reached by the firm when evaluating and reporting on the effectiveness of its QC system and (2) the results of the EQCF's evaluation.

of having evaluated the significant judgments made and related conclusions reached by the firm when evaluating and reporting on the effectiveness of the firm's QC system. However, depending on the nature and degree of their responsibility, ability, or authority to affect the conduct of the firm's associated persons, as established by the firm, the EQCF could be subject to Sarbanes-Oxley section 105(c)(6).

The Board has not required the results of the EQCF's evaluation to be publicly disclosed.¹⁹² However, nothing set forth in this release would limit or prohibit firms from disclosing any information about the EQCF's activities—including the EQCF's practices, methods, or procedures, or the manner or results of the EQCF's evaluation—if the firm chooses.

Based on comments received and experience with inspections of firms' systems of quality control, the Board believes that investors, audit committees, and other stakeholders will benefit from the EQCF's evaluation even in the absence of public disclosure. An external oversight function should enhance the discipline with which the firm carries out its own QC system evaluation. As the Board observe the implementation and performance of the EQCF through its inspection activities, the PCAOB may publish observations or good practices. For these reasons, the Board believes that the EQCF will support improvements in firms' systems of quality control, ultimately benefiting investors, audit committees, and other stakeholders.

People internal and external to the firm can help a firm identify instances of noncompliance with applicable professional and legal requirements earlier than might be possible through the firm's own monitoring.¹⁹³ The proposal included a specified quality response requiring policies and procedures for addressing potential noncompliance with applicable professional and legal requirements and with the firm's policies and procedures with respect to the QC system, the firm's

engagements, firm personnel, or other participants.

This would include clearly defining channels within the firm that enable reporting of complaints and allegations by firm personnel and external parties (e.g., employees of companies or other participants) and establishing procedures for appropriately investigating and addressing such complaints and allegations, including complying with any applicable reporting or other requirements.¹⁹⁴

The proposal sought comment on the appropriateness of this specified quality response, and whether any additional specified quality responses should be considered. Two firms that commented supported the specified quality response. Two other firms expressed concern with the prescriptiveness of other participants being included in the requirement. One investor suggested there should be an explicit requirement for a whistleblower mechanism with key protections such as confidentiality and protection against retaliation, and that the individual responsible for the firm's QC system be responsible for the investigation of whistleblower complaints and remediation of QC issues identified by whistleblowers.

The Board adopted the specified quality response with some modifications, described below. The Board believes that establishing policies and procedures that support the reporting and investigation of potential noncompliance will assist firms in complying with applicable professional and legal requirements. It will also assist them in identifying and dealing with individuals, including those in leadership, who fail to comply with applicable professional and legal requirements or the firm's policies and procedures. Finally, it may result in firm personnel or external parties identifying and communicating deficiencies in the QC system.

The final provision retains the reference to other participants, as the Board believes it is important for the firm to capture any potential noncompliance with applicable professional and legal requirements,

including with regard to work performed by other participants that relates to the firm's QC system or the firm's engagements.

The Board has expanded the requirements related to the firm's policies and procedures for collecting and addressing complaints and allegations to explicitly require that they:

- Be made available to all firm personnel and other participants;
- Address processes and responsibilities for receiving, investigating, and addressing complaints and allegations; and
- Include protecting persons making complaints and allegations from retaliation.

The Board also expanded the specified quality response to require firms that issued audit reports with respect to more than 100 issuers during the prior calendar year to include confidentiality protections in their policies and procedures.

The firm's policies and procedures regarding complaints and allegations should be made available to all firm personnel and other participants, which could occur by posting them on an intranet site or providing such policies and procedures to other participants upon engagement. The policies and procedures should include identifying who is responsible for receiving, investigating, and addressing complaints and allegations; describing the process for submitting complaints and allegations; and describing how the firm will investigate and address complaints and allegations received. The Board also specified that the policies and procedures should explicitly address protection against retaliation of persons making complaints and allegations, which the Board believes is a critical element of any effective program for receiving complaints and allegations.

The required policies and procedures regarding investigating and addressing complaints and allegations allow scalability. The process for investigating and addressing a complaint or allegation would vary, commensurate with and responsive to the significance of the complaint or allegation.

For firms that issued audit reports with respect to more than 100 issuers during the prior calendar year, the policies and procedures will have to provide a confidential and anonymous submission process for complaints and allegations, similar to the requirements for audit committees under the Exchange Act.¹⁹⁵ For example, a firm

¹⁹² For a discussion of certain legal constraints imposed by Sarbanes-Oxley on the Board's ability to require public disclosure of certain QC-related information, see Section IV.L.1.c.ii. As part of a separate project, the Board has proposed a requirement for firms that have an EQCF to disclose the identity of the person or persons, an explanation for the basis of the firm's determination that each such person is independent of the firm (including the criteria used for such determination), and the nature and scope of each such person's responsibilities. See PCAOB Rel. No. 2024-003.

¹⁹³ In addition, through this process information may be received regarding noncompliance with laws and regulations by companies that engage the firm.

¹⁹⁴ A firm's program for addressing complaints and allegations may be subject to requirements under applicable law regarding whistleblowers (such as, for example, N.Y. Labor Law Section 740). However, such a program should not be confused with a whistleblower program established and administered by the Federal government, including the program administered by the SEC, which has its own requirements and protections. See, e.g., 17 CFR 240.21F-1 through .21F-18. To the extent a firm's program for addressing complaints and allegations provides protective measures, such as confidentiality and non-retaliation, based only on firm policy and not on law, such protective measures may not create legally enforceable rights.

¹⁹⁵ See 15 U.S.C. 78j-1(m).

may have a confidential and anonymous submission process through a website, toll-free number, or mobile app, and could manage the process in-house or through a third-party provider. The firm's policies and procedures will also have to provide for protection, during the investigation, of the confidentiality of individuals and entities who make complaints and allegations. The Board believes this requirement specifically targets and responds to potential quality risks that are more likely to arise in audit practices of a certain size and complexity. However, firms that are not subject to this express requirement may nevertheless determine that such requirements are a necessary or appropriate quality response to address their quality risks.

2. Current PCAOB Standards

Existing PCAOB QC standards contain limited references to firm governance and leadership. For example:

- QC 20 acknowledges that the QC system includes the firm's organizational structure;¹⁹⁶
- The SECPS member requirements on independence quality controls provide that the importance of compliance with such independence standards, and the QC standards, should be reinforced by management of the member firm, thereby setting the appropriate tone at the top and instilling its importance into the professional values and culture of the member firm;¹⁹⁷ and
- The SECPS member requirements provide that member firms should communicate to all professional firm personnel the broad principles that influence the firm's quality control and operating policies and procedures on, at a minimum, matters related to the recommendation and approval of accounting principles, present and potential client relationships, and the types of services provided, and inform professional firm personnel periodically that compliance with those principles is mandatory.¹⁹⁸

Ethics and Independence

This component addresses the fulfillment of firm and individual responsibilities under relevant ethics and independence requirements. Adhering to such requirements is a foundational concept that not only promotes audit quality but also safeguards the vital role that auditors play within the capital markets.

The ethics and independence component of the standard has been tailored to the ethics and independence requirements that apply to engagements performed under PCAOB standards. Under the standard, ethics and independence requirements include the PCAOB's ethics and independence standards and rules, the SEC's rule on auditor independence, and other applicable requirements regarding accountant ethics and independence, such as those arising under state law or the law of other jurisdictions (e.g., obligations regarding client confidentiality).¹⁹⁹ The Board clarified that the reference to other applicable requirements is limited to those that are relevant to fulfilling auditor obligations and responsibilities in the conduct of engagements or in relation to the QC system. The standard requires firms to establish quality objectives related to ethics and independence requirements and design and implement specified quality responses.

1. QC 1000

a. Ethics and Independence Quality Objectives (QC 1000.31)

Understanding of and compliance with ethics and independence requirements are fundamental to the auditor's role. Adherence to standards of professional ethics is as important as adherence to requirements regarding auditor independence, and firms' QC systems should address both. Under the standard, firms are required to establish quality objectives that address understanding of and compliance with ethics and independence requirements. While maintaining independence and adhering to ethical requirements is each individual's responsibility, the firm also has responsibility and plays a critical role in ensuring that individuals understand those requirements and have the tools and resources they need to comply.

One firm suggested that the Board clarify the ethical requirements that are subject to the responsibility of the individual assigned operational responsibility for the firm's compliance with ethics and independence

requirements. The firm specifically commented that competence and due care are characteristics required by both ethical standards and QC standards, and as a result, there could be confusion over whether such requirements are ethical requirements or quality control requirements when determining the responsibility of the individual assigned operational responsibility for the firm's compliance with ethical and independence requirements. In some cases, a matter may be applicable to the responsibilities of both the individual assigned operational responsibility for the firm's compliance with ethics and independence requirements and the individual assigned operational responsibility and accountability for the QC system as a whole. A firm could divide responsibilities based on the specific issues involved, so long as the lines of responsibility are clear (for example, duties of competence and due care in the context of the audit, codified under the PCAOB's ethics rules, could be assigned to the individual with operational responsibility for compliance with ethics and independence requirements, while duties of competence and due care in the context of QC system activities, codified in QC 1000, could be assigned to the individual with operational responsibility for the QC system).

Under the standard, the firm is required to establish a quality objective to identify conditions, relationships, events, and activities that could result in violations of ethics and independence requirements and evaluate and respond to such conditions, relationships, events, and activities on a timely basis. This will help the firm reduce the risk of noncompliance by identifying potential violations of ethics and independence requirements in time to prevent many violations and to quickly remediate violations that do occur. For example, a firm that plans to acquire another firm could identify the acquisition as an event that could result in independence violations by the personnel of the acquired entity. This could prompt the firm to develop policies and procedures that address onboarding processes for firm personnel of acquired entities around independence. These policies and procedures would assist in identifying and resolving potential independence violations before the acquisition is completed. One firm commented that as the proposed quality objectives for ethics and independence are broadly consistent with other jurisdictional and international quality control/management standards, it

¹⁹⁶ See QC 20.04.

¹⁹⁷ See SECPS 1000.46.

¹⁹⁸ See SECPS 1000.08(l).

¹⁹⁹ Footnote 10 to QC 1000 provides: Ethics and independence requirements include PCAOB independence and ethics standards and rules, the U.S. Securities and Exchange Commission ("SEC") rule on auditor independence, and other applicable requirements regarding accountant ethics and independence that are relevant to fulfilling their obligations and responsibilities in the conduct of engagements or in relation to the QC system, such as those arising under state law or the law of other jurisdictions. See, e.g., 17 CFR 210.2-01, and PCAOB Rules under Section 3. *Auditing and Related Professional Practice Standards*, Part 5—*Ethics and Independence*.

believes that they are appropriate, and no further changes are needed.

An investor-related group expressed concern that the proposal did not sufficiently address conflicts of interest, such as when an audit firm performs other services for the audited company. The investor-related group further commented that without clear separation between those responsible for quality control and those responsible for maintaining client relationships and winning consulting contracts, investors can have less than full confidence the system of quality control will ensure the necessary level of audit quality. The Board acknowledges that QC 1000 does not create new requirements regarding auditor independence. However, in relation to the commenter's specific concern about the performance of non-audit services, QC 1000 requires the QC system to operate over compliance with numerous restrictions on non-audit services that exist under current independence rules enacted in response to previous independence conflicts.²⁰⁰

QC 1000 establishes quality objectives that apply to all firms. Within the ethics and independence component, firms are required to establish quality objectives that address both personal and firm-level compliance. Personal violations include such matters as owning stock in companies that are audit clients of the firm or its affiliated entities while a "covered person in the firm."²⁰¹ Firm-level violations include such matters as providing prohibited services or failing to obtain required audit committee pre-approval. The Board has also included specified quality responses that directly address the firm's policies and procedures for identifying and monitoring firm and personal relationships with audit clients to help mitigate the risk of potential violations. In addition, the roles and responsibilities requirements direct firms to assign an individual operational responsibility for the firm's compliance with ethics and independence requirements to provide oversight specifically focused on this area.

The quality objectives address compliance with ethics and independence requirements not just by firm personnel, but also by others who may be subject to ethics and independence requirements in relation to work they perform on behalf of the firm. These others may include, for example, "persons associated with a public accounting firm" as defined in

PCAOB rules²⁰² or "covered persons in the firm" under the SEC independence rule.²⁰³ The Board notes that these and other concepts used in the ethics and independence rules do not map directly to the terminology the Board generally uses in QC 1000. (For example, some "other participants," such as other accounting firms, are subject to independence requirements, while others, such as engaged specialists and the company's internal auditors, are not.) To ensure that the requirements for this component of the QC system align with, and do not go beyond, the ethics and independence requirements over which the QC system would operate, in this component the Board uses terminology that incorporates or refers back to the underlying ethics and independence requirements. For example, rather than having quality objectives address compliance by "other participants," in this component the quality objective addresses compliance by "others subject to [ethics and independence] requirements."

One firm commented that it supported the direction of the quality objectives, but asserted that some of the terms were confusing as it related to "others subject to ethics and independence requirements." The firm questioned whether these correspond to other participants as defined in the standard. The firm further commented that the terminology used for others subject to ethics and independence requirements could create operational challenges because those terms are open to interpretation and requested that the Board clarify the language the standard used. The firm suggested that the proposed requirements that contain this language could go beyond the intended applicability of the independence rules to the various parties contemplated. Again, the Board uses terminology in this component that incorporates or refers back to the terminology used in ethics and independence rules, terminology which it believes is well understood in those contexts. The Board uses it precisely to avoid going beyond the scope of existing ethics and independence requirements, and to ensure that QC 1000 addresses exactly the same population as the ethics and independence rules themselves.

One firm commented that while the proposed quality objectives for ethics and independence are appropriate and important, further clarification may be

needed of how the objectives apply to firm personnel. Specifically, the firm argued that it could be inferred that the ethics and independence requirements extend to all individuals involved in the operation of the firm's QC system, including those individuals who are not subject to the requirements under the existing PCAOB and SEC independence rules, for example, data research teams. QC 1000 does not impose ethics and independence requirements on individuals who are not currently subject to them. References in the standard to "requirements" and "obligations" are to existing requirements and obligations which themselves specify to whom they apply. However, firms may choose to implement broader policies regarding ethical behavior that impose requirements on individuals who are not subject to the ethics and independence rules of the PCAOB and the independence rule of the SEC.

With respect to the timing of communication of violations to the individual assigned operational responsibility for the firm's compliance with applicable ethics and independence requirements, the quality objective states that such actions should take place on a timely basis. One firm agreed that timely communication of ethics and independence related matters within the firm is important for audit quality, but expressed concern that the prescriptive nature of the requirements addressing communications may detract from the achievement of the intended objectives. The firm suggested that it is important to recognize that the evaluation of certain matters would be done in accordance with the firm's policies and procedures, which are designed to strike a balance between prematurely alerting individuals to matters for which the facts and potential impacts are not sufficiently known and making sure those with ultimate responsibility for decisions are made aware on a timely basis. The final standard does not specify that all violations need to be communicated immediately. However, the Board believes timely communication and action should be sufficiently prompt to achieve its objective. In some cases, for example, where there is a high risk of a severe or pervasive problem, communication and action may have to be immediate to be timely.

b. Ethics and Independence Specified Quality Responses (QC 1000.32–.36)

The specified quality responses are primarily based on existing PCAOB ethics and independence requirements and SEC independence requirements,

²⁰⁰ See, e.g., 17 CFR 210.2–01(c)(4); PCAOB Rules 3522–3526.

²⁰¹ See 17 CFR 210.2–01(f)(11).

²⁰² See PCAOB Rule 1001(p)(i).

²⁰³ For example, because the definition of "accounting firm" under 17 CFR 210.2–01(f)(2) includes associated entities, "covered persons in the firm" may include personnel of network affiliates in addition to firm personnel.

including the provisions regarding independence quality controls that currently apply to SECPS member firms.²⁰⁴ The Board incorporated these SECPS member requirements into QC 1000, with some refinements, and extending those requirements to all firms. The Board's view is that the SECPS requirements address matters that are generally relevant to a QC system operating over compliance with SEC and PCAOB independence rules. Since those rules apply to all firms that perform engagements for issuers and broker dealers, the Board believes it is appropriate to extend the SECPS requirements to all firms.

Under the standard, the firm is required to design, implement, and maintain policies and procedures for the following:

- General ethics and independence matters;
- Certain specific matters that may reasonably be thought to bear on independence;
- Communication regarding ethics and independence policies and procedures; and
- Mandatory training on ethics and independence.

One firm commented that it generally supports the specified quality responses and believes that it is appropriate to have the same set of independence requirements apply for all firms. Another firm suggested that the specified quality responses are not necessary to achieve the objectives of QC 1000. Instead of prescriptive specified responses, the firm suggested that the standard include more specified quality objectives which would promote scalability and allow for future adaptations to technological or other innovations. Another commenter said that the proposal expanded on the independence requirements in a granular manner and suggested that the details be moved into an appendix or practice aid or provided as additional guidance to help reduce differences between QC 1000 and other standard setters. The specified quality responses for the ethics and independence component primarily carry forward existing requirements from the PCAOB's QC standards and extend certain existing requirements to all firms. The Board believes that the specified quality responses relate to risks that apply to all firms and therefore should be addressed by all firms. The Board intends them to be obligations of all firms and have therefore codified them within the rule text rather than as guidance.

i. QC Policies and Procedures About General Ethics and Independence Matters (QC 1000.33)

The standard requires the adoption of policies and procedures regarding general ethics and independence matters, carrying forward current PCAOB and SEC requirements.

The proposed requirement in QC 1000.33.a did not draw comment and was adopted as proposed.

The phrase "may reasonably be thought to bear on independence" is used in PCAOB Rule 3526²⁰⁵ and should be familiar to all firms. It is taken from an independence standard that predates the existence of the PCAOB,²⁰⁶ and, as the Board noted in connection with the adoption of Rule 3526, it focuses auditors on the perceptions of reasonable third parties when making independence determinations. It is consistent with the SEC's general standard on independence.²⁰⁷ The firm's policies and procedures are required to address all matters that may reasonably be thought to bear on the independence of the firm, firm personnel, and affiliates of the firm under SEC and PCAOB rules.

In addition to the broad concept of matters that "may reasonably be thought to bear on independence," SEC and PCAOB rules address certain specific matters that bear on independence. For example, 17 CFR 210.2–01(c) sets forth a non-exclusive list of circumstances that the SEC considers to be inconsistent with independence.²⁰⁸ Such circumstances include, among others, certain financial relationships, employment relationships, business relationships, non-audit services, contingent fees, and circumstances related to partner rotation. PCAOB rules also list certain prohibited tax transactions and tax services that would make the firm not independent of its client.²⁰⁹

The underlying facts and circumstances and relevant requirements will determine what actions need to be taken by the firm to address a matter that may reasonably be thought to bear on independence. For example, in some situations, it will be

sufficient to communicate the matter to the audit committee. In other situations, further action may be required.

The proposed requirements in QC 1000.33.b–c did not draw comment and were adopted substantially as proposed.

Integrity and objectivity are important ethical concepts currently addressed in QC 20.²¹⁰ Under the existing standard, integrity requires personnel to be honest and candid within the constraints of client confidentiality, whereas objectivity imposes the obligation to be impartial, intellectually honest, and free of conflicts of interest.

As discussed in more detail below, the Board rescinded the interim ethics and independence standard, ET 102, *Integrity and Objectivity*, and replacing it with a new standard, EI 1000, *Integrity and Objectivity*.²¹¹ QC 1000 includes a reference to that new rule and to PCAOB Rule 3500T, *Interim Ethics and Independence Standards*.

The final standard clarifies that firm personnel are expected to demonstrate integrity and objectivity in carrying out all of their professional responsibilities associated with the QC system and the performance of engagements. This includes activities ranging from the design and implementation of the QC system, monitoring and remediation, and evaluation of the QC system, to training and professional development; planning, performing, and supervising engagements; and internal and external communications. The Board also believes that it is important for the firm's policies and procedures to address obligations related to integrity and objectivity for associated persons of the firm, other than firm personnel, who perform work on behalf of the firm.

The proposed requirement in QC 1000.33.d did not draw comment and was adopted as proposed.

Establishing a consultation process on independence matters is an existing concept under SECPS independence requirements. Currently, SECPS member firms are required to designate a senior-level partner responsible for overseeing the adequate functioning of the firm's independence policies and consultation process.²¹²

The Board expanded this concept in QC 1000 by covering not only independence matters, but also ethics matters, and by expressly requiring the firm's policies and procedures to address the identification of ethics and independence matters that require consultation. The Board believes the

²⁰⁵ See PCAOB Rule 3526 (requiring auditors to describe to the audit committee relationships that may reasonably be thought to bear on independence).

²⁰⁶ See Independence Standards Board Standard No. 1, *Independence Discussions with Audit Committees*. ISB No. 1 was included in the Board's interim standards until it was superseded by the adoption of Rule 3526.

²⁰⁷ See 17 CFR 210.2–01(b).

²⁰⁸ See 17 CFR 210.2–01(c).

²⁰⁹ See PCAOB Rule 3522, *Tax Transactions*; PCAOB Rule 3523, *Tax Services for Persons in Financial Reporting Oversight Roles*.

²¹⁰ See QC 20.10.

²¹¹ See Rescission of ET Section 102; adoption of EI 1000; related amendments.

²¹² See SECPS 1000.46 (requirement 5).

²⁰⁴ See SECPS 1000.46.

specific focus on identifying matters requiring consultation should prompt firm personnel and others subject to such requirements to more effectively identify ethics and independence issues that are new, challenging, or complex and that would benefit from evaluation by subject matter experts. The Board applied the requirement to all firms, not just SECPS member firms.

Under existing SECPS requirements, member firms are required to establish a monitoring system to determine that corrective actions are taken on all apparent independence violations reported by firm personnel.²¹³ Under those requirements, the monitoring system should include procedures to provide reasonable assurance that (i) investments of the firm and its benefit plans are in compliance with the firm's policies and (ii) information received from its partners and managers is complete and accurate. The SECPS requirements do not prescribe specific activities for the monitoring system, other than stating that generally it includes auditing, on a sample basis, selected information such as brokerage statements, or alternative procedures that accomplish the same objective. One firm requested clarification of whether auditing, on a sample basis, selected information such as brokerage statements, will be mandatory under QC 1000. The standard does not prescribe specific activities to monitor compliance with ethics and independence requirements and the firm's ethics and independence policies. This allows scalability based on the firm's size and specific circumstances. The Board expects that firms that have developed monitoring systems to comply with SECPS requirements would continue to use these systems as one aspect of monitoring compliance under the standard. While auditing brokerage statements is not mandatory under QC 1000, the firm must design, implement, and maintain policies and procedures to monitor compliance with applicable ethics and independence requirements and related firm policies and procedures. Based on the firm's size and specific circumstances, a firm can choose which monitoring activities are an effective response to meet the quality objective.

With respect to compliance with applicable ethics and independence requirements by the firm and its affiliates, the Board understands that firms employ various manual and automated tools for evaluating whether the firm and its affiliates comply with SEC and PCAOB independence

requirements and the firm's independence policies and procedures. Some examples of such tools include having a centralized process to monitor business relationships, establishing an independence confirmation process that includes detailed guidance and questions related to independence and prohibited non-audit services, and periodic review of the completeness and accuracy of information reported on independence confirmations.

A firm may establish ethics and independence policies and procedures that are more restrictive than the rules of the SEC and PCAOB—for example, to comply with requirements of other jurisdictions or to simplify compliance with SEC and PCAOB requirements by setting bright-line policies and reducing the range for individual judgment. Under the standard, the firm's evaluation of compliance covers applicable ethics and independence requirements as well as the firm's policies and procedures.

The proposed requirements in QC 1000.33.f were adopted substantially as proposed.

As previously discussed, QC 1000 includes the existing SECPS requirement for firms to have policies and procedures that address independence violations and expands the requirement to cover all firms and to include ethics violations.

Under the standard, the firm is required to establish policies and procedures addressing violations and potential violations of ethics and independence requirements. These types of policies and procedures are intended to be preventive, detective, and corrective by nature.

The firm's policies and procedures are required to address identifying conditions, events, relationships, or activities that could constitute ethics or independence violations involving the firm, firm personnel, and, with respect to work performed on behalf of the firm, others subject to such requirements. For example, if a firm or its network is contemplating a reorganization or restructuring that would affect the relationships among affiliated firms or other entities, identifying post-reorganization investment activities as such an activity could assist the firm in designing and implementing appropriate policies to prevent independence violations.

With respect to ethics and independence violations that do or could occur, the firm's policies and procedures are required to address the taking of preventive and corrective actions to address violations on a timely basis. Such policies and procedures

could specify the individuals responsible for taking preventive and corrective actions (at the engagement or firm level), the timing of preventive and corrective actions, and any potential sanctions against firm personnel or other individuals for violating ethics and independence requirements. While one firm supported bringing greater attention and accountability to the ethics and independence component, it suggested that the level of prescription may create operational challenges that could be detrimental to audit quality. Specifically, with regards to paragraph .33f.(2), the firm commented that ethical or independence violations may take a variety of forms and that dictating that preventive and corrective actions must be taken does not promote a risk-based approach. The standard requires that a firm's policies and procedures address, with respect to violations and potential violations, the taking of preventive and corrective actions, as appropriate. Ethics or independence violations may take a variety of forms, and therefore the nature and extent of the preventive and/or corrective actions may also take a variety of forms commensurate to the severity and pervasiveness of the violation.

The firm's policies and procedures are required to address reporting of ethics and independence violations. QC 1000 requires that firm personnel and others performing work on behalf of the firm that are subject to the ethics and independence requirements report both their own violations and other violations of which they become aware that may affect the firm. The Board revised the language in proposed paragraph .33f.(3) to clarify that the requirement applies to others performing work on behalf of the firm that are subject to the ethics and independence requirements.

The standard takes a principles-based approach, which allows each firm to determine which reporting mechanisms best fit its structure and address its quality risks. Through the Board's oversight activities, it has observed that firms employ various mechanisms for firm personnel to report violations. Some examples include direct communication lines to an ethics and independence group, designated individuals within the human resources department or the legal department, and whistleblower hotlines.²¹⁴ Firms may assess each case individually and involve appropriate subject matter experts, depending on the nature of the

²¹³ See SECPS 1000.46 (requirement 7.d).

²¹⁴ See, e.g., paragraph .29 of QC 1000, discussed above, for requirements regarding firm processes for addressing complaints and allegations.

violation. Some firms also establish escalation protocols for certain types of ethics and independence violations (e.g., violations involving a partner in the firm).

In addition, the firm's policies and procedures are required to address any communications that need to take place as a result of a violation of ethics and independence requirements. For example, PCAOB Rule 3526 requires certain communications to the audit committee regarding matters that are thought to bear on the firm's independence, including violations of independence requirements.

ii. QC Policies and Procedures About Certain Matters That May Reasonably Be Thought To Bear on Independence: Restricted Entities, Independence and Ethics Certifications, and Matters Requiring Audit Committee Pre-Approval

Under the standard, the firm's policies and procedures on matters that may reasonably be thought to bear on the independence of the firm are required to address, among other things, (1) restricted entities, including the maintenance and dissemination of the list of restricted entities; (2) independence and ethics certifications; and (3) matters requiring audit committee pre-approval.

(1) Restricted Entities (QC 1000.34.a–d)

Most of the requirements related to restricted entities come from existing SECPS member requirements,²¹⁵ which will now apply to all firms. Under the standard, as under current requirements, restricted entities include all audit clients (including affiliates of the audit client) of the firm and affiliates of the firm. One firm commented that the proposal did not define “affiliates” and recommended either referencing the definition provided in PCAOB Rule 3501 or defining the term in the standard in a manner similar to Rule 3501. “Audit client,” “affiliate of the audit client,” and “affiliate of the accounting firm” are terms defined in existing PCAOB and SEC rules.²¹⁶ As

²¹⁵ The SECPS term “restricted entities” includes all audit clients of the firm (and, where applicable, its foreign-associated firms) that are SEC registrants, along with other entities that the firm is required to be independent of under the applicable SEC requirements.

²¹⁶ “Audit client” is defined for purposes of SEC rules in 17 CFR 210.2–01(f)(6), and for purposes of PCAOB rules in PCAOB Rule 3501(a)(iv). “Affiliate of the audit client” is defined in PCAOB Rule 3501(a)(ii) as having the same meaning as defined in 17 CFR 210.2–01(f)(4). “Affiliate of the accounting firm” is defined in PCAOB Rule 3501(a)(i) and, for purposes of the Note to paragraph .34a, “accounting firm,” which includes

proposed, paragraph .34 includes a footnote referring to those definitions.

Existing SECPS requirements require firms that audit more than 500 SEC registrants to have an automated system to identify investment holdings of partners and managers that might impair independence.²¹⁷ As proposed, the Board required an automated system for firms that issued audit reports with respect to more than 100 issuers during the prior calendar year. The Board understands that firms that audit more than 500 SEC registrants already have automated systems in place, based on the SECPS requirements to have an automated system 17 CFR 210.2–01(d).²¹⁸ Firms that issued audit reports for 100 or fewer issuers are required to consider whether the system needs to be automated, taking into account the quality risks and the nature and circumstances of the firm. For example, a firm with close to 100 issuers and a significant number of managers and partners may assess timely identification of personal investments that may impair independence as a quality risk, and a quality response to address that risk may include an automated system to help facilitate a more timely relationship-checking process.

One firm commented that the specified quality response to have an automated process for identifying direct or material indirect financial interests is appropriate, and another firm commented that it did not object to the requirement. However, a firm and a firm-related group recommended that the PCAOB consider if the existing SEC requirements are sufficient such that no additional PCAOB requirements are needed, and several firms commented that the costs of implementing the requirement would be significant and instead the threshold should be increased to 500 issuers to be consistent with the SEC requirements. Some of these firms suggested that the cost may be a potential barrier to entry for firms approaching the 100-issuer audit client

the firm's associated entities, is defined in 17 CFR 210.2–01(f)(2).

²¹⁷ See SECPS 1000.46 (requirement 4).

²¹⁸ 17 CFR 210.2–01(d) provides that a firm's independence is not impaired solely because a covered person in the firm is not independent of an audit client, provided the covered person did not know of the circumstances giving rise to the violation, the violation was corrected as promptly as possible, and the firm maintains a quality control system meeting specified standards. 17 CFR 210.2–01(d)(4), describes, for firms that provide audit, review, or attest services to more than 500 SEC registrants, features necessary for the firm's QC system to meet the specified standards, including an automated system to identify investment holdings of partners and managers that might impair independence.

threshold. One of these firms commented further that some firms that audit over 100 issuers will consider decreasing the size of their practice due to the associated cost of the requirement. This firm suggested that the specified quality response be removed and instead, if necessary, implement a quality objective that firms could address through their risk assessment process. Several firms suggested that firms that audit more than 100 but no more than 500 issuers could consider implementing such a process, but it should not be required. One firm-related group suggested that the threshold for requiring an automated independence system be reduced further, given the number of repeated independence issues among all firms.

One firm expressed concerns with both the proposed requirement in paragraph .34a.(1) and the suggestion in paragraph .34a.(2) to automate this process, suggesting that this would be cost prohibitive and firms should design processes that reflect their respective size, complexities and risks identified. Another firm commented that firms subject to the current SECPS requirements have likely invested significant capital and resources to implement and maintain tools that enable compliance with those requirements, and while the firm views that investment as worthwhile and believes the procedures have contributed to audit quality over the years, it expressed concerns for the cost of the requirement to firms that audit between 100 and 500 issuers. Another firm commented that it has such an automated system in place, however it suggested that the implementation of such a system within the timeframe set out in the proposed standard may be challenging and costly. One firm commented that the determination of whether or not to implement an automated process for identifying and tracking direct and material indirect financial interests should be risk-based and not include a prescriptive requirement based on an arbitrary count of greater than 100 issuers. The firm specifically commented that the size, scope, nature, and complexity of firms' issuer practices can vary significantly among the annually inspected firms, noting for example that a large portion of its issuer client count consists of Form 11–K audits and smaller reporting companies. Another firm commented that while the size of the firm's client base is one factor to consider in determining an appropriate quality response, the nature and circumstances of the firm and the firm's clients are also

factors that should be taken into consideration, as well as the firm structure, industries served, and number of managers and partners.

Some firms sought clarity as to whether an automated process would be required for other financial relationships, for example, employment relationships, business relationships, or non-audit services, and commented that the identification of certain financial relationships cannot be easily automated. Instead, the firms suggested limiting the requirement to automate the process for identifying investments in securities that might impair independence, to align with the SEC requirement. A number of firms and a firm-related group requested clarity on what “automated” means and what the Board’s expectations are with regards to the nature, extent and scope of automation.

After consideration of the comments, the Board adopted the 100-issuer threshold as proposed. The Board believes it is important to maintain a consistent threshold for the incremental requirements in QC 1000. As discussed in more detail above, the Board believes that the 100-issuer threshold is appropriate, and while the nature of each firm’s audit client list may vary, there still exist complexities inherent to firms with a large number of issuer audit clients that may give rise to quality risks that apply to the firm’s independence, for which the automated system would be an appropriate quality response.

The Board clarified in the final standard that the requirement for an automated process is limited to the process to identify investments in securities that might impair the independence of the firm or firm personnel, the same scope as required under 17 CFR 210.2–01(d). The Board has observed through its oversight activities that some firms have systems that automate the identification of their professionals’ investment holdings through direct broker feeds, but a direct broker feed is not the only type of automated process that would meet the Board’s requirement. As discussed in a December 9, 1999, letter from the SEC’s Chief Accountant,²¹⁹ firms need to develop a system that tracks audit engagements and financial investments held by professionals such that the conflict verification process is automated. Such a system may rely on firm professionals accurately self-

reporting and entering their investments into the system in a timely manner. These holdings would automatically be compared to the list of restricted entities to identify any relationships with restricted entities. Based on the size of the firm and other characteristics, a firm may determine that a direct broker feed is an appropriate quality response (for example, if the firm’s monitoring activities found high rates of non-compliance by firm personnel with the firm’s policies and procedures for reporting financial investments), but a direct broker feed is not expressly mandated for firms subject to the requirement to implement an automated process. The Board also made a change to require that the process described in paragraph .34a.(1) must be automated to conform to the degree of responsibility that the requirement imposes on the auditor to that required under paragraph .34.

One firm suggested that a longer transition period be provided for firms that are not currently subject to a requirement to implement an automated system. The firm commented that if two firms merged and one or both of the firms had previously not been subject to the requirement, it is unlikely that a system of this nature could be implemented and tested for effectiveness in the time period provided. The Board believes that firms continuously monitor the size of their audit practice relative to the 100-issuer threshold, and if a firm is considering a transaction such as a merger that would increase its number of issuer audit clients significantly, then the firm could begin to implement such a system in advance of the end of the calendar year in which the firm first surpasses the 100-issuer threshold. Indeed, for a transaction such as a merger of audit firms, the Board believes that there could exist specific risks to independence as a result, which in itself may result in a firm developing an automated system as a quality response.

Current SECPS requirements require timely (generally monthly) communication of additions to the Restricted Entity List.²²⁰ The proposal contemplated requiring that firms have policies and procedures for maintaining and making available the list of restricted entities to firm personnel and others performing work on behalf of the firm who are subject to independence requirements, and updating and communicating changes to the list of restricted entities at least monthly to such persons.

Several firms and a firm-related group suggested the specified quality response

be replaced with a quality objective regarding updates to and awareness of changes in the restricted entity list. Two of these firms suggested that the requirement be amended to limit communications to additions to the restricted entity list. Another firm suggested communications be limited to firm personnel subject to independence requirements and the requirements should allow for flexibility in the nature, timing, and extent of communications. QC 1000 does not enlarge the population of individuals who are subject to ethics and independence requirements. References in the standard to “requirements” and “obligations” are to existing requirements and obligations which themselves specify to whom they apply. In addition, after consideration of the comments received, the Board amended the standard to limit the required communications to additions to the list of restricted entities, rather than all changes.

Some firms did not support this communication to “others performing work on behalf of the firm,” and suggested that communications should be limited to potential covered persons affected by the additions. Two of these firms commented that these individuals would likely not be considered covered persons for engagements other than the engagement they are working on, and suggested that the Board allow firms to take a risk-based approach when determining the scope and frequency of the communications. Another firm suggested that QC 1000 does not need to specifically address certain communications to other participants where this is required by another standard, specifically AS 2101 (as in effect for audits of fiscal years ending on or after December 15, 2024) paragraph .06D, which includes a “written description of all relationships between the other auditor and the audit client of persons in financial oversight roles at the audit client that may reasonably be thought to bear on independence. Another firm commented that the goal of alerting others performing work on behalf of the firm to specific engagement independence requirements could be achieved through engagement-specific independence certifications.

After consideration of the comments received, the Board amended the standard to require at least monthly communication of additions to the list of restricted entities to firm personnel and others performing work on behalf of the firm whose relationships and arrangements with such additional restricted entities may reasonably be thought to bear on the independence of

²¹⁹ See Letter From the Chief Accountant: Issues Related to Independence/Quality Control to SEC Practice Section (II) (Dec.9, 1999), available at <https://www.sec.gov/info/accountants/staffletters/cal1129a.htm>.

²²⁰ See SECPS 1000.46 (requirement 5).

the firm. The Board believes that it is appropriate to limit communications of additions to the list of restricted entities to firm personnel and others performing work on behalf of the firm to those additions that could reasonably be thought to bear on the independence of the firm. For example, additions to the affiliate list for an issuer would be relevant for an individual who is performing work on behalf of the firm on that issuer, or a partner who is located in the same office of the firm in which the lead audit engagement partner primarily practices in connection with the audit. This communication should be made as frequently as necessary, and on at least monthly basis, through the period that the individual is subject to the independence requirements.

Several firms and a firm-related group commented that the requirement to communicate the restricted entity list would not be more effective than the automated systems already in place at larger firms. Two firms also commented that smaller firms with infrequent changes to the restricted entity list may not need to communicate changes monthly. One of these firms suggested that many firms already have policies where individuals are required to review the restricted entities list prior to purchasing stock/during proposal/acceptance procedures to determine whether an independence conflict would exist, and that many firms also make those restricted lists readily available to employees as part of their current QC systems. The Board believes, and has observed through its oversight activities, that such automated systems may not fully mitigate quality risks associated with the timely reporting of financial relationships by firm personnel, for example, if the automated system is not equipped to identify certain financial relationships, or if the firm is reliant on its professionals making timely reporting of these relationships into the firm systems. The Board believes that requiring the communication of additions to the list of restricted entities to firm personnel whose relationships and arrangements with such additional restricted entities may reasonably be thought to bear on the independence of the firm on an at least monthly basis may prompt firm personnel to report a previously unreported relationship. If there are no additions, there is no required communication.

One firm commented that it is unclear whether communication is intended to mean a distributed communication (e.g., email of the updated list) or communication can be made available

(e.g., a website that hosts such list and is readily available to access). Some firms may decide to communicate updates to the list of restricted entities on a more frequent basis, as changes are being made, or in more targeted ways (such as to particular offices or engagement teams). The standard does not prescribe the method of communication. Through the Board's oversight activities, it have observed that some firms comply with existing SECPS requirements by communicating additions to the list of restricted entities to all firm personnel weekly via email. These firms could continue that practice to comply with the standard. However, other methods that result in an effective communication may also be acceptable; for example, a firm might communicate that there have been additions to the list of restricted entities via email, and include within the email a link to an accessible website-hosted list of additions.²²¹ While the standard requires communications of additions to those individuals whose relationships and arrangements with such additional restricted entities may reasonably be thought to bear on the independence of the firm, the firm may choose to extend the communications of additions more broadly. In addition, if the firm communicates additions to less than all firm personnel, then the firm must have correctly identified the group of people whose relationships and arrangements with such additional restricted entities may reasonably be thought to bear on the independence of the firm.

The standard does not prescribe a specific process for maintaining and making available the list of restricted entities to firm personnel and other individuals. Firms are able to determine the specific methods and tools needed to keep the list of restricted entities up to date and to ensure that any additions are communicated on a timely basis to firm personnel and other individuals. This determination is based on factors such as the size of the firm, the number of audit clients, and the complexity of those clients (e.g., the number of audit client affiliates). For example, a smaller firm with a small group of professionals, a stable portfolio of audit clients, and a manual process for maintaining the list of restricted entities may decide to communicate changes monthly. For a larger firm with many audit clients and firm affiliates, an automated tool could help facilitate more frequent updates to the list of restricted entities. The firm is

²²¹ Firms are required to communicate additions to the list of restricted entities. For periods where there were no changes, no such communication would be required.

required to notify relevant professionals of additions to the list at least monthly.

The Board recognizes that some firms are members of networks that may develop systems, processes, and controls to monitor network firms' compliance with independence requirements, including maintaining a database of restricted entities. As described above, the standard does not prescribe a specific process for maintaining a database of restricted entities, so this process could potentially be performed by a network or outsourced to a third party. At the same time, the standard requires each firm to establish its own quality objective, which places responsibility on the firm with respect to resources or services provided by the network or a third-party provider.²²²

The Board incorporated into QC 1000 the existing SECPS requirements for firm personnel²²³ to review the list of restricted entities prior to obtaining any security or other financial interest in an entity, but with the following refinements:

- Require firm personnel to review the list of restricted entities, not only before they or their relevant family members²²⁴ obtain a direct or material indirect financial interest in an entity or enter into a direct or material indirect relationship with an entity,²²⁵ but also after additions to the list of restricted entities are communicated by the firm, upon firm personnel's employment at the firm, prior to changes in position (e.g., going into a chain of command or other covered person role²²⁶), and prior to entering into or modifying any business or employment relationships.

- Require the firm and firm personnel to take required actions on a timely basis if the review of the list of restricted entities indicates that action is required under applicable professional and legal requirements or the firm's policies and procedures.

Under this approach, the firm's policies and procedures will require

²²² See below for a discussion of the firm's responsibilities when it uses resources or services provided by a network or third-party provider.

²²³ SECPS requirements use the term "professionals," which means professional staff, including partners. See SECPS 1000.46 (requirement 1.a).

²²⁴ Context determines which family members would be relevant. See, e.g., 17 CFR 210.2–01(f)(9) (defining "close family members"); 17 CFR 210.2–01(f)(13) (defining "immediate family members"); see generally 17 CFR 210.2–01(c) (referring to "close family member" or "immediate family member" depending on the context).

²²⁵ The Board is using the terms direct and material indirect in the same sense as 17 CFR 210.2–01(c).

²²⁶ "Covered persons in the firm" is defined in 17 CFR 210.2–01(f)(11).

that the list of restricted entities be reviewed before the firm enters into any relationship, engagement to perform non-audit services, or fee arrangement that might affect compliance with independence requirements. This requirement serves the same purpose as review of the list of restricted entities by the firm personnel and helps the firm to identify relationships that may result in noncompliance with applicable professional or legal requirements.

One firm commented that, rather than requiring that the list of restricted entities be reviewed before the firm enters into any relationships, engagements to perform non-audit services, or fee arrangements that might affect compliance with independence requirements, firms should be permitted to develop quality responses to identify prohibited relationships and fee arrangements that appropriately respond to quality risks, based on the firm's facts and circumstances. The firm also suggested that the requirement for firm personnel to review the list of restricted entities after changes to the list are made should be deleted since firm personnel would already be notified of changes based on paragraph .34b. The Board believes these specified quality responses are appropriate and should be addressed by all firms, regardless of the specific facts and circumstances of the firm. In addition, the Board views the requirements of paragraph .34b for the firm to maintain and make available the list of restricted entities, and paragraph .34d for firm personnel to review the list of restricted entities, as separate.

(2) Independence and Ethics Certifications (QC 1000.34.e)

Certifications are intended to drive greater accountability for firm personnel's compliance with independence requirements and to deter independence violations. The certification requirement is similar to an existing SECPS requirement, which requires each professional to certify near the time of initial employment and at least annually thereafter that he or she (1) has read the member firm's independence policies, (2) understands their applicability to his or her activities and those of his or her spouse and dependents, and (3) has complied with the requirements of the member firm's independence policies since the prior certification.²²⁷

The proposal contemplated obtaining certifications from firm personnel regarding familiarity and compliance with SEC and PCAOB independence

requirements and the firm's independence policies and procedures (1) upon employment, (2) at least annually thereafter, and (3) upon any change in personal circumstances, such as firm role, geographic location, or marital status, that is relevant to independence.

Several commenters, including firms, did not support the requirement to obtain additional certifications upon changes in personal circumstances, and three firms raised practical concerns when the changes involved marital status. One firm suggested that the standard should emphasize that a firm's independence certification process should consider timeliness in addressing the quality objective, and instead encourage firms to consider the appropriateness of obtaining periodic certifications throughout the year. One firm commented that a firm should have flexibility to determine its own policies and procedures for certifications beyond requiring them at employment and annually thereafter; the firm suggested that, for example, quarterly certification accompanied by training on the impact of life events may be more effective and practicable than event-driven review and certification. Another firm recommended that firms be allowed to develop their own quality responses based on their own unique quality risks when personal circumstances change rather than requiring certification upon changes in personal circumstances as a quality response. Another firm suggested that this requirement should instead be managed through proper education and awareness of relevant independence requirements. Another firm suggested that these items would be better suited as examples of considerations included in implementation guidance. One firm suggested that the certification requirements should be applicable for firms with over 500 issuers that already have an automated independence system. The firm further commented that the requirement is onerous in terms of being able to identify the data on a timely basis and suggested a semi-annual representation period instead of circumstance-driven.

In addition, the proposing release sought feedback on whether the standard should require annual written certification regarding familiarity and compliance with ethics requirements and the firm's ethics policies and procedures, in addition to those regarding independence. The proposing release further asked whether firms should be required or encouraged to adopt firm-wide codes of ethics or similar protocols. One firm did not

support a specific quality response that includes a certification process for ethics requirements and procedures. The firm suggested that firms should be permitted to adopt a quality response that addresses the risks within their own practice, and that a certification requirement that applies to all firm practice staff could turn into a "check-the-box" compliance exercise that would not benefit audit quality. One firm commented that such requirements would already be addressed by the requirement for mandatory training in paragraph .36. Other commenters, including firms, investors, and investor-related organizations, supported the requirement to obtain a written annual certification regarding familiarity and compliance with ethics requirements and the firm's ethics policies and procedures. One of these investors commented that the main argument against such certifications is that it imposes a cost and that it becomes a "tick-the-box exercise," but in the investor's view the cost is de minimis given other annual declarations needed by firm personnel, and firm leadership can send an appropriate signal by embracing the ethics code to stop such annual declarations becoming a perfunctory exercise. One firm and an investor-related organization supported a requirement that firms should adopt firm-wide codes of ethics.

After consideration of the comments received, the Board made two changes to the final standard. First, the Board removed from the standard the requirement to obtain a certification from firm personnel regarding familiarity and compliance with SEC and PCAOB independence requirements and the firm's independence policies and procedures upon any change in personal circumstances, and replaced this with the requirement that such a certification must be obtained for any change in professional circumstances that is relevant to independence. Rather than include examples of such changes in the text of the standard, the Board provided in this release some examples of changed professional circumstances that may be relevant to the independence of the firm's personnel under applicable independence rules. These examples include changes within the firm such as promotions, moving offices, or changing practice groups (e.g., changes to covered person status). Although, in connection with this change, the Board removed a certification requirement with regard to changes in personal circumstances, such changes can have independence implications under SEC and PCAOB

²²⁷ See SECPS 1000.46 (requirement 7.b).

independence requirements, and a firm's QC system must provide reasonable assurance of compliance with those requirements. Secondly, the Board added a requirement for certification by firm personnel regarding familiarity and compliance with the applicable ethics requirements and the firm's ethics policies and procedures as the Board believes such certification will enhance individual accountability and, ultimately, compliance. The Board not added a requirement for firms to adopt a firm-wide code of ethics or similar protocol, because it believes that firms should have flexibility to determine whether this would assist them in meeting the relevant quality objectives.

The standard does not prescribe a checklist of specific content for the certifications, focusing instead on general concepts of familiarity and compliance. It is possible that the form of certification called for by the existing SECPS requirement would satisfy the standard. In addition, the standard expands on the existing SECPS requirement by requiring firms to obtain certifications every time firm personnel have a change in professional circumstances that is relevant to independence, such as a change in role or geographic location. Changes within the firm such as promotions, moving offices, or changing practice groups may have consequences under independence rules (e.g., changes to covered person status) and result in noncompliance. The Board continues to believe that a specified quality response requiring specific event-driven independence and ethics certifications appropriately considers timeliness in addressing the quality objective and applies to quality risks that exist in all firms.

(3) Matters Requiring Audit Committee Pre-Approval (QC 1000.34.f)

The proposed requirement did not draw comment and was adopted as proposed. QC 1000 contains a new requirement regarding firm policies and procedures for identifying matters that require pre-approval by the audit committee and obtaining such approval. The primary responsibility for identifying matters that require audit committee pre-approval and obtaining such pre-approval resides at the engagement level. The firm's policies and procedures, however, provide tools and guidance that enable engagement teams to properly identify the relevant matters and obtain necessary pre-approvals on a timely basis. Through the Board's oversight activities, it has observed numerous instances where firms did not have an effective

mechanism in place for monitoring whether matters that require audit committee pre-approval were properly disclosed to audit committees. The new requirement should lead to more consistent compliance.

iii. Communication of Changes to Ethics and Independence Policies and Procedures (QC 1000.35)

The proposed requirement did not draw comment and was adopted as proposed. The final standard incorporates existing SECPS requirements regarding the dissemination of the firm's independence policies and procedures and expands the requirements to cover ethics policies and procedures.

When deciding how to make ethics and independence policies and procedures available, firms would consider how to make firm personnel and others performing work on behalf of the firm aware of where and how to find these policies and procedures in a way that supports those individuals' ongoing compliance with certification and other requirements. The standard requires the firm to communicate any substantive changes to its ethics and independence policies and procedures on a timely basis.

iv. QC Policies and Procedures About Mandatory Ethics and Independence Training (QC 1000.36)

The proposed requirement did not draw comment and was adopted as proposed.

The standard includes a requirement for mandatory periodic training on ethics and independence, which expands on the existing SECPS requirements that cover training on independence. The mandatory training requirement promotes awareness and understanding of the ethics and independence requirements, which should lead to better compliance with such requirements. Under existing SECPS requirements, firms are required to establish a training program for professionals to complete near the time of initial employment and periodically thereafter.²²⁸

The specific content and extent and timing of the training will be determined by the firm, but the program is required to cover both the relevant professional and legal requirements (for example, regarding financial interests, business relationships, employment relationships, proscribed services, and fee arrangements) and the firm's related policies and procedures.

By not specifying the content for such mandatory training, the standard allows firms the ability to develop training programs based on their circumstances. For example, a firm may develop its training to place a greater emphasis on areas with recurring ethics and independence findings across the firm, or it may target specific ethics and independence findings in different regions. Similarly, the standard does not specify how the firm would provide such training. A firm may develop and deliver its own training, contract with others to provide training, or provide access to third-party training.

Under the standard, the firm is required to provide such training at least annually, or more often as needed.

2. Current PCAOB Standards

QC 20 provides that policies and procedures should be established to provide the firm with reasonable assurance that personnel maintain independence (in fact and in appearance) in all required circumstances, perform all professional responsibilities with integrity, and maintain objectivity in discharging professional responsibilities.²²⁹ The SECPS member requirements regarding independence quality controls apply only to certain firms. The requirements for ethics and independence discussed above are more detailed than the existing requirements in QC 20 and Appendix L of the SECPS and would apply to all firms.

Acceptance and Continuance of Engagements

This component addresses the firm's processes when considering whether to accept or continue an engagement.

1. QC 1000

a. Acceptance and Continuance of Engagements Quality Objectives (QC 1000.38)

The proposal described the quality objectives related to acceptance and continuance of engagements. Several commenters, including firms, were generally supportive of the proposed quality objectives.

A commenter on the AS 1000 rulemaking objected to the use of the term "client" in that standard to refer to the company and its management. The commenter suggested "company under audit" instead. The Board agrees with the commenter that the terminology used in the PCAOB standards should help to remind auditors that they work for the benefit of investors, not the management of the company.

²²⁸ See SECPS 1000.46 (requirement 3).

²²⁹ See QC 20.09.

Accordingly, the Board generally replaced references to the “client” with references to the “company” or eliminated them altogether (for example, this component, called “Acceptance and Continuance of Client Relationships and Specific Engagements” in proposed QC 1000, is “Acceptance and Continuance of Engagements” in the final standard). The Board, however, retained references to the “client” where that aligns with other rules, such as in the area of independence.

The quality objectives in this component were adopted substantially in the form proposed, with the exception of the change throughout to focus on the engagement instead of the client relationship and the other clarifications discussed below.

Acceptance and continuance of engagements is an aspect of a firm’s compliance and risk management process. Each firm, depending on its nature and circumstances, may approach acceptance and continuance of engagements differently. The acceptance and continuance of engagements process assists the firm in mitigating reputational, business, and litigation risk. The quality objectives stress the importance of focusing the acceptance and continuance of engagements process on the firm’s ability to perform an engagement in accordance with applicable professional and legal requirements.

i. Timing (QC 1000.38.a(1))

The proposed standard required the firm’s judgment about whether to accept or continue an engagement to be made as part of or before performing preliminary engagement activities. Preliminary engagement activities, which are activities the auditor should perform at the beginning of the audit, are described in AS 2101.06.

One commenter stated that the proposed requirement implied that the judgment was only made during preliminary activities and not throughout the engagement. The Board clarified the quality objective in paragraph .38a(1) to specify that the initial judgment is to be made as part of or before preliminary engagement activities. QC 1000.40, discussed below, addresses the firm’s obligation to continue to address situations that could have caused it to decline the engagement had the information been known prior to acceptance and continuance.

ii. Independence and Permissibility of Services (QC 1000.38.a(2)(a) and (b))

This proposed quality objective did not draw significant comment and was adopted as proposed.

The firm’s ability to perform the engagement includes considering whether the firm is independent and whether the services are permissible. These are threshold considerations for acceptance and continuance, because in general, under PCAOB standards the firm is not allowed to accept an engagement unless it is independent of the company for which the engagement will be performed and the services are permissible under applicable professional and legal requirements (including obtaining audit committee pre-approval where that is required).

The firm’s policies for acceptance and continuance in the areas of independence, permissibility of services, and pre-approval relate to and to some extent overlap with the ethics and independence component. The requirements in the ethics and independence component more generally address the ongoing evaluation of compliance with applicable professional and legal requirements relating to the independence of the firm, firm personnel, and others subject to such requirements.

iii. Access to Company Information and Company Personnel (QC 1000.38.a.(2)(c))

This proposed quality objective did not draw significant comment and was adopted substantially as proposed.

The firm’s ability to perform an engagement in accordance with applicable professional and legal requirements depends on the firm’s ability to obtain information from the company and gain access to individuals at the company who can respond to the firm’s inquiries. Restricted or limited access to company information or personnel—for example, due to language differences, physical location, or local law restrictions—could impair the firm’s ability to perform the engagement in accordance with applicable professional and legal requirements.

iv. Resources (QC 1000.38.a(2)(d))

Another aspect of the firm’s ability to complete the engagement in accordance with applicable professional and legal requirements is the resources available to the firm. The Board believes it is important for a firm to have the right resources available so that the engagement can be performed in

accordance with applicable professional and legal requirements. This includes the availability of resources like the following, either internal or external to the firm:

- Firm personnel or other participants with competence to perform procedures (*e.g.*, industry experience or experience with new or specialized accounting pronouncements that apply to the company) and sufficient availability to meet audit timing requirements;
- Engagement partners;
- Specialists;
- EQRs;
- Technology to be used in the performance of the engagement, such as technology for testing the implementation and effectiveness of automated processes; and
- Intellectual resources needed in the performance of the engagement (*e.g.*, industry-specific audit programs).

One commenter suggested that consideration should be given to the availability of industry-specific resources at the partner and manager level and the Board agrees that industry-specific resources are important in certain audits. However, the Board believes that issue is adequately addressed by the general reference to “resources to perform the engagement,” which includes industry-specific resources where those would be needed. The Board adopted this quality objective as proposed.

v. Other Relevant Factors (QC 1000.38.a(2)(e))

This proposed quality objective did not draw comment and was adopted as proposed.

The firm’s ability to perform engagements in accordance with applicable professional and legal requirements may also be affected by other factors associated with providing professional services in the particular circumstances. Accordingly, the standard, by directing firms to consider such other relevant factors, retains the breadth and inclusiveness of QC 20.15b, which requires the firm to establish policies and procedures to provide reasonable assurance that the firm appropriately considers the risks associated with providing professional services in the particular circumstances.

v. Information About the Nature and Circumstances of the Engagement, Including the Integrity and Ethical Values of the Company (QC 1000.38.a(3))

In order for the firm to make appropriate judgments about whether to accept or continue an engagement, the

firm needs to obtain sufficient information about the nature and circumstances of the engagement (*e.g.*, the nature of the company and the environment in which it operates) and the integrity and ethical values of the company, including its management and audit committee.²³⁰ This information is relevant because it can help identify potential risks to performing the engagement that may result in the firm not being able to perform the engagement in accordance with applicable professional and legal requirements. The nature and circumstances of the engagement may, for example, reveal the need for specialized expertise that the firm does not have. A lack of management integrity may affect the reliability of the company's accounting records. Designing and implementing policies and procedures that direct and standardize the collection and evaluation of such information could help the firm in consistently making appropriate judgments about whether to accept or continue an engagement. Additionally, information obtained during the firm's acceptance and continuance process about the nature and circumstances of the engagement and the integrity of management and the audit committee would in many cases be relevant when planning and performing the engagement.²³¹

One commenter requested clarification of whose integrity and ethical values are relevant to the consideration of "the integrity and ethical values of the company (including management and the audit committee)"—for example, whether consideration could be limited to the audit committee chair. Since members of management and the audit committee all have influence over the company's financial reporting, the Board believes their integrity and ethical values are important to the judgment of accepting or continuing an engagement. Therefore, consistent with the proposal, the final standard does not include such a limitation.

The quality objective in QC 1000.38.b retains the concept in QC 20.16 of having policies and procedures regarding obtaining an understanding with the company about the engagement and aligns with similar requirements under PCAOB auditing and attestation

standards.²³² Achieving this objective should minimize the risk of misunderstandings regarding the nature and scope of the engagement and any limitations associated with it.

c. Acceptance and Continuance of Engagements Specified Quality Response (QC 1000.39–.40)

The proposal included a specified quality response regarding policies and procedures to address situations where the firm learns of information that would have caused it to decline a previously accepted engagement. Two commenters were generally supportive of the proposed specified quality response.

Under this specified quality response, the firm's policies and procedures are required to address situations in which the firm becomes aware of relevant contrary information after the firm's decision to accept or continue an engagement. This contrary information may have existed at the time of the decision to accept or continue an engagement but not been known by the firm at the time, or it may have emerged subsequent to that decision. Depending on the circumstances, appropriate responses may include such actions as:

- Consulting with legal counsel or others within the firm to determine if the firm is able to continue the engagement;
- Discussing the information with management and the audit committee to determine if the firm is able to continue the engagement;
- Including this information in the auditor's risk assessment procedures so that any additional risks are responded to during the audit; and
- Withdrawing from the engagement and notifying appropriate regulatory authorities as required under applicable professional and legal requirements.

One commenter suggested that specific circumstances should require an immediate reconsideration of client continuance, such as illegal acts, fraud, or material omissions of fact. Existing auditing standards, such as AS 1301, include requirements related to evaluating the continuation of the client relationship. The QC system would address compliance with these requirements.

Under the proposal, a firm would be deemed to have become "aware" of information if any partner, shareholder, member, or other principal of the firm was aware of such information, the

same standard that applies with respect to the reporting of specified events on Form 3. One commenter stated that the concept of when a firm becomes "aware" should take into account the size and scale of the firm, and the nature of the matters related to the QC system, suggesting that alignment with the requirements of Form 3 may be inappropriate because of Form 3's relatively limited scope compared to the matters addressed by QC 1000. The Board continues to believe that it would be inappropriate to differentiate among firm principals in this regard; all firm principals should be responsible for promptly communicating and acting upon relevant information. Accordingly, the class of persons whose awareness is attributed to the firm was not been narrowed.

Another commenter recommended clarifying the timing of when a firm becomes "aware" of information subsequent to accepting or continuing a client relationship. Footnote 26 of the final standard reflects the suggested clarification that the firm is deemed "aware" of information when any partner, shareholder, member, or other principal of the firm "first becomes aware" of such information.²³³

2. Current PCAOB Standards

The quality objectives of QC 1000 paragraph .38 do not fundamentally change a firm's existing responsibilities regarding acceptance and continuance decisions under QC 20.²³⁴ The quality objectives expand on the requirements in QC 20 with regard to considering the necessary information and making appropriate judgments about the associated risks and the firm's ability to mitigate those risks and perform an engagement in accordance with applicable professional and legal requirements.

Engagement Performance

This component addresses the firm's processes relating to the performance of the firm's engagements in accordance with applicable professional and legal requirements. Engagement performance encompasses the activities of firm personnel and other participants in all phases of the design and execution of the engagement—planning, performing, supervising, and documenting the engagement; conducting an engagement quality review; and making

²³⁰ For a prospective engagement, this includes evaluating information obtained from a predecessor firm. See generally, *e.g.*, AS 2610, *Initial Audits—Communications Between Predecessor and Successor Auditors*.

²³¹ See, *e.g.*, AS 2110.41–.45.

²³² See paragraph .05 of AS 1301, *Communications with Audit Committees*, and paragraph .46 of AT Section 101, *Attest Engagements*.

²³³ This approach aligns with the instructions to Form 3, under which a firm is deemed aware of reportable facts on the first day that any partner, shareholder, principal, owner, or member of the firm first becomes aware of the facts. See Form 3, Note to Instructions to Part II.

²³⁴ See QC 20.14–.16.

communications regarding the engagement.²³⁵ In order for the firm to consistently deliver compliant engagements, including when performing work on other firms' engagements, firm personnel and other participants need to understand and fulfill their responsibilities in accordance with applicable professional and legal requirements.

1. QC 1000

The proposal described the quality objectives for the engagement performance component and asked if there should be any specified quality responses for this component. Firms that commented were generally supportive of the proposed quality objectives. Two commenters wanted clarity on why some concepts in auditing standards were or were not included in QC 1000. One of these commenters, an investor-related group, suggested the standard address certain areas like fraud protection, crypto assets, climate change, and critical audit matters. The Board believes these areas are engagement-level specific, whereas QC 1000 focuses on the firm-level controls over engagement responsibilities. Commenters, including firms and related groups, were also supportive of not providing specified quality responses in this component. The Board adopted these provisions substantially as proposed.

Under QC 1000, a firm is required to establish quality objectives for the engagement performance component in the following areas:

- Engagement responsibilities;
- Consultations and differences in professional judgment; and
- Engagement documentation.

a. Engagement Responsibilities (QC 1000.42.a)

This proposed quality objective did not draw comment and was adopted as proposed.

The standard uses the term "engagement partner" with its existing meaning under PCAOB audit and attestation standards: the member of the engagement team²³⁶ with primary responsibility for the audit, examination, or review, as the case may be.²³⁷ The definition of "engagement"

under QC 1000, under which substantial role work is defined as an engagement, does not change the meaning of engagement partner or affect the responsibilities of individuals involved in substantial role engagements. No comments were received on the use of this term.

i. Responsibilities of the Engagement Partner (QC 1000.42.a(1))

The engagement partner is responsible for the engagement and its performance, including managing and achieving consistent compliance with applicable professional and legal requirements on the engagement. This quality objective focuses firms on partner involvement throughout the engagement, including appropriately supervising firm personnel and other participants.²³⁸

ii. Due Professional Care (QC 1000.42.a(2)(a))

Due professional care means acting with reasonable care and diligence, exercising professional skepticism, acting with integrity, and complying with applicable professional and legal requirements.²³⁹ In the context of engagement performance, professional skepticism is an attitude that includes a questioning mind and critical assessment of audit evidence and other information that is obtained to comply with PCAOB standards and rules. Exercising professional skepticism improves the quality of judgments made while performing the engagement and is key to performing an engagement in good faith and with integrity. PCAOB oversight activities have suggested that the lack of professional skepticism contributes to some of the QC deficiencies identified during PCAOB inspections.²⁴⁰ As an example, a firm's policies and procedures did not provide reasonable assurance that engagement partners supervised engagements with due professional care, which contributed to the failure to identify deficiencies in those engagements.

The quality objective related to due professional care, including professional skepticism, enables appropriate conclusions to be reached that are supported by sufficient appropriate evidence.²⁴¹

iii. Supervision (QC 1000.42.a(2)(b))

Proper supervision aims to ensure that work is performed as directed and supports the conclusions reached.²⁴² The quality objective emphasizes the importance of firm personnel and other participants being supervised properly, consistent with AS 1201 and AT No. 1.

iv. Reporting and Other Communications (QC 1000.42.a(3))

PCAOB standards and rules impose a number of requirements relating to reporting and communicating the results of the engagement.²⁴³ The engagement report and communications to the audit committee are typically prepared at the engagement level and may include information provided by the firm. For example, the firm may provide information related to independence to be communicated in accordance with PCAOB Rule 3524 or PCAOB Rule 3526. This quality objective emphasizes the importance of auditor reporting and communication in accordance with applicable requirements.

b. Consultations and Differences in Professional Judgment (QC 1000.42.b-.c)

Consultations are an important aspect of engagement performance, as they provide a mechanism to discuss and resolve complex, unusual, or unfamiliar matters with individuals who have the requisite knowledge, skill, and ability. Under current PCAOB standards, QC 20.19 highlights the significance of consultations, requiring appropriate policies and procedures. The quality objective should drive firms to continue to focus on the importance of consultation and resolution before the issuance of an engagement report.

The quality objective in the proposed standard provided that consultations on complex, unusual, or unfamiliar accounting and auditing matters are undertaken with qualified individuals from within or outside the firm.

One commenter suggested that the standard require firms to adopt policies that identify situations when national office consultation is required. The Board does not believe it is appropriate to include such prescriptiveness in the standard, as not all firms have national offices. Additionally, the quality objective provides that the firm will identify the risks specific to their

²³⁵ See QC 20.18.

²³⁶ The term "engagement team" is used as defined in the amendments to AS 2101, *Audit Planning*, adopted in PCAOB Rel. No. 2022-002, which takes effect for audits of financial statements for fiscal years ending on or after Dec. 15, 2024.

²³⁷ See AS 1201.A2; AT No. 1 at paragraph .07 note; AT No. 2 at paragraph .06 note. AT 101 uses the term "practitioner with final responsibility for the engagement," which the Board construes as having the same meaning.

²³⁸ See generally, e.g., AS 1201.

²³⁹ The general principles and responsibilities of the auditor when conducting an audit, including professional skepticism and due professional care, are being reaffirmed and combined in AS 1000, as adopted. See Auditor Responsibilities Release.

²⁴⁰ See, e.g., 2022 Broker-Dealer Inspection Report, at 31.

²⁴¹ See Roles and Responsibilities above.

²⁴² See AS 1201.02.

²⁴³ See generally, e.g., AS 3101, *The Auditor's Report on an Audit of Financial Statements When the Auditor Expresses an Unqualified Opinion*; AS 2201.85-.89; AS 1301; paragraphs .34-.38 of AT No. 1; and AT 101.63-.90.

engagements and determine whether there are specific situations that always require consultation.

Another commenter said that the reference to “unfamiliar” accounting and auditing matters was unclear and was concerned that it creates an unnecessary level of prescription that will be difficult to operationalize. The commenter also expressed concern that an unintended consequence could be that auditors may infer that consultations may compensate for lack of competence on the engagement team. The final standard retains the term, consistent with the use of “unfamiliar” in current QC 20.19. It is noted that inclusion of that term in paragraph .42 does not modify or limit auditor obligations to have the competence necessary to conduct the engagement established elsewhere in PCAOB standards.

Differences in professional judgment may occur when there is a concern or disagreement regarding the application of applicable professional and legal requirements during the performance of the engagement. The quality objective underscores the importance of having and adhering to appropriate procedures for the resolution of differences in professional judgment during the performance of engagements such that the firm, firm personnel, and other participants comply with applicable professional and legal requirements.

The proposed quality objective provided that differences in professional judgment related to the engagement are brought to the attention of the individual(s) with responsibility and authority for resolving such matters and are resolved before the issuance of an engagement report. One commenter suggested clarifying that if the engagement partner does not agree with the conclusions arising from the consultation (addressed above), that would be treated as a difference in professional judgment that would require compliance with the quality objective regarding differences of professional judgment. The final standard clarifies that point.

c. Engagement Documentation (QC 1000.42.d)

This proposed quality objective did not draw significant comment and the Board adopted as proposed.

AS 1215 contains the general requirements for the documentation the auditor should prepare and retain in connection with engagements. 17 CFR 210.2–06 also addresses documentation retention requirements.²⁴⁴ The quality

objective regarding engagement documentation in proposed QC 1000 is meant to drive firms to focus on compliance with these requirements.

2. Appendix K Requirements

Existing PCAOB standards (referred to as Appendix K requirements) require SECPS member firms that are associated with international firms or networks to seek adoption of policies and procedures by their associated international firms or network regarding filing reviews, inspection procedures, and disagreements between the engagement partner and the reviewer.²⁴⁵ As noted in the proposal, the Board believes that the purposes originally intended to be served by Appendix K have either been eliminated (through the elimination of the U.S. GAAP reconciliation) or otherwise addressed (through requirements for engagement quality review). Accordingly, the Board proposed to not retain requirements like those in Appendix K.

The proposal asked whether the PCAOB should eliminate Appendix K and rely exclusively on a risk-based approach. Commenters had mixed views regarding the retention of Appendix K requirements. Some commenters supported the elimination of Appendix K requirements and reliance on a risk-based approach. Other commenters asserted that the Appendix K requirements are beneficial and should be retained or made even more prescriptive. The Board believes it unnecessary to retain the Appendix K requirements because under the risk-based approach, firms will have to assess and respond to quality risks including, if applicable, a relative lack of experience in performing engagements under U.S. professional and legal requirements.

Some commenters expressed concern that in a risk-based approach, a person performing a limited review function similar to the current Appendix K reviewer would be considered part of the engagement team, while another commenter requested clarification that such a reviewer would not necessarily be a member of the engagement team. Under QC 1000, the firm’s assessment of quality risks will determine the nature and extent, if any, of additional resources or reviews that would need to be performed over engagements to

ensure compliance with PCAOB and SEC requirements. In some circumstances, the response might involve adding one or more additional members to the engagement team. In other circumstances, the response might involve resources that would not constitute members of the engagement team because they perform a contemporaneous quality control function and do not perform audit procedures or help plan or supervise the audit work.²⁴⁶

One commenter expressed concern that reviewers’ firms would be considered “other accounting firms” and reviewers’ hours would be included for purposes of Form AP filings. Specific to Form AP filing requirements, firms should review the Note to Item 3.2 of the Form AP Instructions regarding the reporting of other accounting firms.²⁴⁷

3. Current PCAOB Standards

Under current QC standards, engagement performance covers all phases of the design and execution of the engagement, and engagement quality reviews.²⁴⁸ QC 20 contains general requirements regarding engagement performance, including planning, performing, supervising, reviewing, documenting, and communicating the results of each engagement; referring to authoritative literature; and consulting with qualified individuals when appropriate. QC 20 provides that policies and procedures should be established to provide reasonable assurance that the engagement is performed in accordance with applicable professional standards. QC 1000 retains these concepts from the extant standards.

As discussed above, QC 1000 does not contain provisions similar to the Appendix K requirements that currently apply to former SECPS member firms.

Resources

This component addresses the firm’s responsibilities for obtaining, developing, using, maintaining, allocating, and assigning resources—including people, financial, technological, and intellectual resources—to enable the design, implementation, and operation of the firm’s QC system and the performance of its engagements.

²⁴⁵ See SECPS 1000.08(n) (cross-referencing the objectives set forth in Appendix K, SECPS 1000.45). The types of SEC filings subject to review under Appendix K are registration statements, annual reports on Form 20–F and Form 10–K, and other filings that include or incorporate the foreign associated firm’s audit report on the financial statements of an SEC registrant.

²⁴⁶ See PCAOB Rel. No. 2022–002 at A4–5.

²⁴⁷ See *id.* at A3–19.

²⁴⁸ See QC 20.18.

²⁴⁴ 17 CFR 210.2–06.

1. QC 1000

a. Resources Quality Objectives (QC 1000.44)

The proposal asked if the Board's proposed quality objectives for resources were appropriate. Commenters that responded to this question generally supported the quality objectives. One commenter suggested that the risks associated with the resources component are greater and that a prescriptive approach would be warranted. The Board believes the combination of quality objectives and specified quality responses appropriately provides for scalability and prescriptiveness.

Under QC 1000, a firm is required to establish quality objectives for the resources component in several different areas:

- People;
- Technological resources;
- Intellectual resources; and
- Resources from a network or third-party provider.

i. People (QC 1000.44.a–g)

The quality objectives in QC 1000.44.a–b are similar to the personnel management element of quality control addressed in QC 20 and QC 40, and the Board adopted them as proposed with one change. The proposed standard included a note that describes what competence comprises—knowledge, skill, and ability—which is derived from QC 40.04.²⁴⁹ Two commenters suggested deleting the last sentence in the note, which as proposed stated that “The measure of competence is qualitative rather than quantitative . . . ,” on the basis that it would discourage the use of quantitative performance metrics. The Board believes that QC 40 should be understood as saying, not that quantitative measures are wholly irrelevant, but that competence is not measured exclusively on a quantitative basis because quantitative measurement alone may not accurately reflect the nature of experience gained over time. The note in the final standard has been revised to clarify that competence can be measured both qualitatively and quantitatively.

These two quality objectives work together in addressing competence from the perspective of both the firm and individual. The firm and its personnel have responsibilities for developing and maintaining competence that will support the operation of the firm's QC

system and the performance of the firm's engagements in accordance with applicable professional and legal requirements and the firm's policies and procedures.

Understanding the competence needed to carry out responsibilities for the operation of the firm's QC system and the performance of the firm's engagements assists a firm in identifying its personnel needs. This understanding also assists a firm in identifying areas for personnel development. Competence can be developed through an appropriate combination of education, professional experience in accounting and auditing with proper supervision, and training such as CPE.

A commitment to quality can be demonstrated through a person's actions and behaviors, including consistent adherence to firm policies and procedures, demonstrating key professional attributes like objectivity, integrity, and due professional care, and taking the initiative to develop and maintain competence. Conversely, a lack of commitment to quality can be seen through actions and behaviors such as inconsistent compliance with professional standards, cheating on professional development and compliance exams, or a “check the box” approach to professional development.

The quality objectives in QC 1000.44.c–e address the assignment of firm personnel and individuals who are other participants, in the firm's engagements, QC roles, and other firms' engagements. As discussed previously, the firm's people resources may include firm personnel (generally, employees of the firm) or resources from outside the firm (other participants). For example, EQRs or personnel at service centers may be considered either firm personnel (if employed by the firm or functioning as firm employees) or other participants (if contracted by the firm).²⁵⁰ One commenter was concerned that the inclusion of other participants in the firm's QC system may create cross-jurisdictional legal issues, such as employment information that may be protected by privacy laws. The Board believes it is important for the QC system to assess the competence of other participants, which may include having policies and procedures on what to do if the firm is unable to make such assessment due to legal issues. One commenter mentioned that the responsibilities related to the use of specialists engaged by the firm, other auditors, and internal auditors providing direct assistance are addressed in existing auditing standards

as engagement team responsibilities and are not needed within this quality objective. While it is acknowledged that there are auditing standards that address those topics at the engagement level, the quality objectives relate to the firm's processes for assigning the appropriate individuals to engagements and QC activities.

One commenter emphasized the need for firm resources to have time to fulfill their assigned responsibilities. Another commenter suggested a prescriptive approach to human capital management, including monitoring assignments and time requirements, utilization, and engagements with high turnover and workloads. Given the wide range of firms based on their size, scope, and nature of practice, the Board does not believe prescriptive requirements in this area are appropriate. The Board clarified paragraphs .44c and .44e by adding “needed” to the quality objective to increase the focus on sufficient competency, objectivity, time, and when appropriate, the authority needed to fulfill their assigned responsibilities. The PCAOB has also separately proposed new reporting requirements regarding firm and engagement metrics that, if adopted by the Board and approved by the SEC, would enhance transparency about, among other things, firms' human capital management.²⁵¹

The quality objectives focus on three key aspects of the ability to fulfill the assigned role: competence, objectivity, and time. Individuals need to have competence to fulfill their assigned roles in accordance with applicable professional and legal requirements and the firm's policies and procedures. As previously discussed, both the individual and the firm play a part in developing a person's competence. The ability to maintain objectivity is essential to performing QC activities or engagements; a lack of objectivity may, for instance, create an unconscious bias that directly affects quality. Individuals' ability to devote appropriate time to their assignments also affects quality.

In addition to the competence, objectivity, and time needed to perform engagement and QC activities, individuals need to have the requisite authority to perform effectively. In the context of engagement activities, the auditing standards already provide authority structures with respect to, for example, supervision and the responsibilities of the engagement partner, and those standards are augmented by firm policies on matters such as consultation. For QC activities,

²⁴⁹ See QC 40.04 (competencies are not measured by periods of time because such quantitative measurement may not accurately reflect the kinds of experiences gained in any given time period).

²⁵⁰ See QC 1000.A5 and .A7.

²⁵¹ See PCAOB Rel. No. 2024–002.

the need for appropriate authority is specified in the quality objective.

The QC 1000.44.f quality objective to comply with the firm's policies and procedures did not attract comment and was adopted as proposed.

This quality objective is based on a concept embedded in QC 20: that firm personnel should adhere to the firm's own standards of quality. The Board believes that this should remain among the firm's objectives, and also that it would play an important role in the operation of the QC system under QC 1000.

The firm's QC-related policies and procedures are essential to the proper functioning of an effective QC system. By definition, those policies and procedures are the "quality responses" the firm has designed and implemented to address quality risks. Firm personnel need to understand those policies and procedures and operate in compliance with them in order for the QC system to operate as designed and achieve its objectives. Additionally, firm personnel need to understand and comply with firm policies and procedures in order for the firm's work on its own engagements and other firms' engagements to be performed appropriately.

Evaluations help support and promote the continuous development of the competence of firm personnel. Some commenters, generally investor-related groups, suggested the standard address incentives in partner compensation relative to quality control systems and weight it at least as much as revenue growth. After considering comments, the Board revised paragraph .44g to add "including through compensation plans and decisions in which quality considerations play a critical part." The Board believes this change will prompt firms to appropriately weight quality concerns in their organization-wide compensation plans and individual compensation decisions. The Board believes his change, along with the change to the quality objective in paragraph .25b, should result in firms giving appropriate weight to quality in compensation plans and decisions regarding performance for both firm leadership and firm personnel.

The quality objective contemplates that evaluations should be performed at least annually. Many firms currently utilize an annual performance review process in order to facilitate such evaluations. A firm may have multiple quality responses to address the quality risks associated with the different types of firm personnel. For example, non-employee contractors and consultants, who work under the firm's supervision

or direction and control and are considered firm personnel, may be evaluated through the contracting process to determine whether the firm should retain them. The quality objective does not specify the format of or approach to periodic evaluations.

The quality objective in QC 1000.44.g, which refers to accountability and incentives, is principles-based, and firms will be able to design and implement incentive systems based upon their nature and circumstances. The "appropriate standards of conduct" identified in the quality objective include fulfilling engagement and QC responsibilities with competence, integrity, objectivity, and due professional care and complying with applicable professional and legal requirements and the firm's policies and procedures, as described in paragraph .46 of the standard.

ii. Technological Resources (QC 1000.44.h)

Technological resources cover many aspects that collectively comprise a firm's technological environment, including information technology applications, infrastructure, and processes (e.g., firm processes to manage access to the IT environment, program changes, changes to the IT environment, or IT operations). Technological resources may be developed by the firm or obtained, for example, from the firm's network or a third-party provider.

The nature and extent of the use of technological resources differs across firms. For example, some audit firms are making significant investments in technological resources and expanding their use of technology-based audit tools, such as software used to perform data analytics or to access information from a distributed ledger. Some technology facilitates the operation of firms' QC systems, such as monitoring individual financial investments for purposes of compliance with independence rules. The availability of "off-the-shelf" technological resources continues to evolve, leading to an increase in firms of all sizes employing technology to assist in operating their QC systems or planning and performing engagements.

The quality objective in QC 1000.44.h highlights that the proper use of technological resources, in a manner that enables the operation of the firm's QC system and the performance of its engagements in accordance with applicable professional and legal requirements and the firm's policies and procedures, is the firm's responsibility. The proposal asked if the quality objective and specified quality

responses related to technological resources provide sufficient direction to enable the appropriate use of emerging technologies. Commenters that addressed this question, generally firms, indicated the proposed quality objectives and specified quality responses provide sufficient direction. One commenter suggested that the standard does not create incentives to use technology to improve audit quality.

The technology environment is dynamic, and firms' use of technological resources will likely continue to evolve in the future. The Board believes that principles-based standards are more adaptable to future developments, less likely to become obsolete, and less likely to discourage the use of emerging technologies. As a result, QC 1000 does not include any prescriptive requirements related to how firms address emerging technology. Instead, it includes a risk factor to prompt consideration of technology as part of the firm's risk assessment process.²⁵² Separately, the Board has proposed certain amendments to PCAOB auditing standards that address certain aspects of designing and performing audit procedures using technology-assisted data analysis of information in electronic format.²⁵³

The Board adopted the technological resources quality objective as proposed. The Board believes the risk-based approach creates incentives for firms to obtain or develop, implement, maintain, and use technological resources throughout the firm based on the size and nature of the firm.

iii. Intellectual Resources (QC 1000.44.i)

The quality objective in QC 1000.44.i related to intellectual resources did not attract comment and was adopted substantially as proposed. The Board revised the note to add "to enable the operation of the firm's QC system," consistent with the quality objective.

Intellectual resources generally include the information the firm uses to promote consistency in the execution of the firm's QC system and the performance of engagements. Intellectual resources may be made available through a variety of media, including via written manuals or technological resources (e.g., the firm's methodology may be embedded in the information technology application that enables the operation of the firm's QC

²⁵² See paragraph .20a.(1)(e) and Appendix B paragraph .B6 of QC 1000.

²⁵³ See Proposed Amendments Related to Aspects of Designing and Performing Audit Procedures that Involve Technology-Assisted Analysis of Information in Electronic Form, PCAOB Rel. No. 2023-004 (June 26, 2023).

system and facilitates the performance of the engagement).

Intellectual resources may be obtained or developed internally, or acquired externally (for example, a commercially available audit or QC methodology or a subscription data feed). Regardless of how intellectual resources are acquired, the firm remains responsible for ensuring they are fit for purpose and properly implementing and maintaining them. For example, if a firm acquired its QC methodology from a vendor, the firm is responsible for choosing a methodology and implementing it (including appropriately identifying risks and designing, implementing, and operating appropriate responses) in a way that enabled the firm's engagements to be properly performed and the firm's QC system to operate in accordance with QC 1000. If a firm developed methodology to direct the performance of its engagements in accordance with applicable professional and legal requirements, and a new auditing standard were issued after that methodology was implemented by the firm, the methodology would need to be updated to properly address the applicable professional and legal requirements.

The quality objective related to intellectual resources in the final standard is similar to the technological resources quality objective, as both objectives relate to resources enabling the operation of the firm's QC system and the performance of its engagements in accordance with applicable professional and legal requirements and the firm's policies and procedures.

iv. Resources From a Network or Third-Party Provider (QC 1000.44.j)

In some circumstances, the firm may use resources provided by a network or a third-party provider. Such resources may include methodologies, applications, and tools used in the firm's QC system or the performance of its engagements.

The proposal included a quality objective in QC 1000.44.j related to the resources provided by a network or a third-party provider. One commenter requested the objective be broken into two quality objectives, as a firm's approach to each of these groups may be significantly different. The Board agrees that a firm's approach to resources provided by the network may be different from resources provided by a third-party provider, and that the approach to different types of third-party providers could also vary. But the Board does not believe that such differences compel separate quality objectives. A firm may identify multiple

quality risks and develop multiple quality responses related to a single quality objective.

For example, a firm may use multiple third-party providers for a variety of different resources, such as an audit methodology provider or a confirmation intermediary. If these different types of third-party providers or resources present different risks, the firm would be required to develop different quality responses. In that scenario, the firm could have different policies and procedures applicable to different types of third-party providers and/or different types of resources. A firm that is not affiliated with a network is not required to establish a quality objective related to network-provided resources and therefore would not identify quality risks or related quality responses.

Notwithstanding that a firm may use resources from a network or a third-party provider, the firm remains responsible for the use of these resources in the QC system and performance of its engagements.

Consideration of the nature of the resources provided by the network or third-party providers, how and to what extent the resources will be used, and the general characteristics of the third-party provider will assist the firm in determining whether it needs to supplement or adapt such resources. For example, the firm may obtain its methodology from a third-party provider under an arrangement whereby the third-party provider agrees to update the methodology when new standards are issued. In this scenario, the firm remains responsible for verifying that such changes are incorporated into the methodology and supplementing the methodology if such changes are not made, so that the firm's resources support its performance of compliant engagements. As another example, the firm may obtain a service from a third-party provider that provides a System and Organization Controls 1 (SOC 1) report. The firm would be responsible for verifying that the controls are designed effectively at the third-party provider and for designing and implementing any complementary user entity controls identified in the report.

The firm is also responsible for taking any necessary actions in using a resource from a network or third-party provider to enable the resource to function effectively. For example, the network or third-party provider may need information related to the firm's restricted entities so that it can facilitate independence confirmations. In addition, if the firm discovered a problem with the design or operation of the resource, it may need to

communicate such problems to the network or third-party provider so that the resource can effectively operate.

b. Resources Specified Quality Responses (QC 1000.45–.51)

The proposal asked if the specified quality responses for resources were appropriate. Two commenters that addressed this question supported the specified quality responses. Two other commenters objected that the specified quality responses were too prescriptive and suggested they be rewritten as risk-based quality objectives.

One commenter stated that certain of these requirements relate closely to auditing standards and requested clarity on how QC 1000 is intended to interact with engagement-related auditing standards. QC 1000 focuses on firm-level controls over compliance with auditing standards, including those related to engagement performance.

The Board adopted the specified quality responses as proposed, with one modification suggested by commenters. These specified quality responses carry provisions from the PCAOB's existing QC standards into QC 1000 or establish firm-level requirements that align with existing engagement-level requirements. They also include new requirements that the Board believes are important to a firm's QC system.

The specified quality response related to appropriate standards of conduct did not attract comment and was adopted as proposed.

The reference to "appropriate standards of conduct" reflects a number of concepts in existing PCAOB standards, including:

- Fulfilling responsibilities with professional competence;²⁵⁴
- Integrity and objectivity;²⁵⁵
- Due professional care (including the exercise of professional skepticism);²⁵⁶ and
- Complying with applicable professional and legal requirements and the firm's policies and procedures.²⁵⁷

Firm personnel are individually responsible for complying with the firm's standards of conduct, and the firm's policies and procedures around these standards of conduct are intended to result in firm personnel being held accountable for their behavior and actions. This includes evaluating firm personnel's adherence to such standards

²⁵⁴ See, e.g., QC 20.13a, .13b, and .15a.

²⁵⁵ See, e.g., QC 20.10.

²⁵⁶ The general principles and responsibilities of the auditor when conducting an audit, including professional skepticism and due professional care, are being reaffirmed and combined in AS 1000, as adopted. See Auditor Responsibilities Release.

²⁵⁷ See, e.g., QC 20.03.

of conduct, addressing deviations, and holding personnel accountable for fulfilling their engagement and QC responsibilities, including through the firm's incentive system. The Board believes the standards of conduct included in this specified quality response are foundational to fulfilling not only engagement responsibilities, but also QC responsibilities.

QC 40 addresses requirements regarding the competencies of engagement partners and, by extension, EQRs.²⁵⁸ The proposed standard, in QC 1000.47, required that firms' QC policies and procedures address certain enumerated competencies, as well as other competencies as necessary in the circumstances. Some commenters suggested that the competencies identified in proposed paragraph .47a-h be moved to a quality objective or staff guidance and argued that they were redundant to the auditing standards. The Board believes that the competencies in paragraph .47 are applicable to all firms and accordingly are appropriate as specified quality responses. One commenter asked for clarification of the expectation of "including an understanding of" and suggested that the standard include consideration of "other competencies as necessary in the circumstances," consistent with QC 40.08. The Board believes that auditors should be familiar with the concept of obtaining an understanding, and note that the construct of QC 40 is a restrictive list whereas the list of competencies in this requirement is identified as "including" and not intended to be comprehensive, so the Board does not believe a reference to other competencies is necessary.

One commenter indicated that the firm would not be in a position to impose the specific requirements in paragraph .47 on individuals that are not part of the firm. The Board has narrowed the requirement to apply only to firm personnel, rather than "others participating in an engagement," as proposed. It is noted, however, that other quality objectives, such as those in paragraphs .44c and .44e, continue to apply with respect to individuals outside of the firm as well as firm personnel. As discussed in more detail above in the Acceptance and Continuance of Engagements discussion, the Board also revised "client" to "company" in paragraph .47.

Paragraph .47 of QC 1000 both expands the required competencies for engagement partners and requires certain competencies for other firm

personnel in engagement roles commensurate with their responsibilities. This includes applying existing requirements for engagement partners—an understanding of, among other things, the importance of exercising sound judgment, the role of the firm's QC system in the performance of engagements, and the industry in which the company operates—to everyone in an engagement role, at a level commensurate with their responsibilities.

To reflect changes in the environment since the existing QC standards were issued, the Board required competencies related to understanding the subject matter of attestation engagements, the internal control framework and technology used by the company, and the technological and intellectual resources used in performing engagement procedures. Regarding technological and intellectual resources, the Board required an understanding of how and whether it is appropriate to use these resources in performing the engagement. This specified quality response does not imply that the engagement partner or other firm personnel participating on an engagement need to be knowledgeable about how such resources are developed.

QC 20 provides that policies and procedures are required to be established to provide the firm with reasonable assurance that personnel participate in CPE and other professional development activities that enable them to fulfill responsibilities assigned and satisfy applicable CPE requirements.²⁵⁹ In addition, SECPS member requirements provide that member firms are required to ensure that (1) all professionals in the firm residing in the United States, including CPAs and non-CPAs, participate in at least 20 hours of qualifying CPE every year and at least 120 hours every three years and (2) professionals who devote at least 25 percent of their time to performing audit, review or other attest engagements, or who have the partner- or manager-level responsibility for the overall supervision or review of any such engagements, must obtain at least 40 percent (eight hours in any one year and 48 hours every three years) of their required CPE in subjects relating to accounting and auditing.²⁶⁰

²⁵⁹ See QC 20.13; QC 40.02, .05.

²⁶⁰ See SECPS 1000.08(d), 8000. The SECPS member requirements provide that "accounting and auditing subjects" should be broadly interpreted, and include, for example, subjects relating to the business or economic environments of the entities to which the professional is assigned.

Through the PCAOB's oversight activities, the Board has observed situations where a lack of understanding of professional standards appears to have contributed to audit deficiencies. These problems have been observed in domestic firms and international firms, including firms that were not SECPS members.

One commenter requested the standard set out more specific requirements with respect to training, identify areas or categories that must be regularly addressed, and not eliminate the CPE obligation in the existing standard. Another commenter requested the standard include minimum requirements related to training of audit staff. The Board believes it is important for firms to provide training focused on areas where firm personnel need to develop or maintain their competence so that they may fulfill their QC and engagement roles. If the Board were to set specific requirements with respect to training, firms may not evolve their training over time to respond to changes in the firm or in the needs of firm personnel. The Board maintained the principles-based approach to training.

Under the specified quality response in QC 1000.48, the firm is required to provide training, including training on applicable professional and legal requirements, that is mandatory for all firm personnel on an annual basis. This specified quality response provides firms the ability to determine the type and extent of training necessary based on their personnel and the nature and circumstances of the firm and its engagements. For example, a firm may determine that training is necessary on a wide array of topics for a certain level of staff within the firm. Another firm may determine that training is necessary for one or more staff in a certain area due to a new engagement or as a result of an area of development identified as part of a performance evaluation. A firm may also decide that it is necessary to repeat training as a periodic reminder of existing requirements, such as those relating to internal control over financial reporting. Ultimately, the type and extent of training should be directed at whatever is necessary to enable firm personnel to fulfill their assigned QC and engagement roles in accordance with applicable professional and legal requirements and the firm's policies and procedures.

This specified quality response in QC 1000.49 did not attract comment and was adopted as proposed.

This specified quality response relates to the quality objective in paragraph .44g, which provides that firm personnel are evaluated at least

²⁵⁸ See, e.g., QC 40.08; AS 1220.05.

annually, incentivized to fulfill their assigned responsibilities and adhere to appropriate standards of conduct, including through compensation plans and performance decisions regarding performance that appropriately prioritize quality considerations, and held accountable for their actions and failures to act.

Specific to the individuals assigned ultimate responsibility and accountability for the QC system as a whole and operational responsibility and accountability for the QC system as a whole, the firm's periodic performance evaluations of these individuals are required to take into account the results of the firm's evaluation of its QC system.²⁶¹ A firm will be able to determine its approach to comply with this specified quality response. For example, the firm may set targets and measure the outcome of the evaluation of the QC system against those targets. As another example, the firm may consider the individual's actions taken in response to identified QC deficiencies or major QC deficiencies, including the timeliness and effectiveness of such actions. The periodic performance evaluation of these individuals may be informal in a less complex firm or undertaken by a special committee in a more complex firm.

No comments were received on the specified quality response in QC 1000.50 and it was adopted as proposed.

Laws or regulations may establish requirements for the professional licensing or other qualifications of the firm and firm personnel. Under this specified quality response, the firm is required to have policies and procedures regarding licensure such that the firm and firm personnel hold the required licenses or qualifications. The policies and procedures address such matters as (1) the jurisdiction(s) where firm and firm personnel are required to hold licenses or other qualifications, and (2) whether the firm and such firm personnel comply with the jurisdictions' requirements.

The quality objective in paragraph .44h. provides that technological resources are obtained or developed, implemented, maintained, and used to enable the firm's QC system and the performance of its engagements. As part of the firm's quality response to this quality objective, the firm's technological resources should also have the characteristics described in paragraph .51. One commenter stated

that the quality objective in proposed paragraph .44h is sufficient and this specified quality response should be removed. The Board believes the firm's policies and procedures should address its technological resources having the capacity (resource requirements for the necessary output), integrity (guarding against improper information modification), resiliency (ability to operate and recover under adverse conditions), availability (ensuring timely and reliable access to and use of information), reliability (ability to function consistently), and security (protection against intentional subversion).²⁶² These characteristics enable the ongoing operation of the firm's QC system and performance of its engagements. The Board believes this specified quality response provides additional direction and has retained it in the final standard.

Also related to technology, the proposal asked if the standard should include a specified quality response that would require the use of technological resources by the firm to respond to the risks related to the use of certain technology by the companies for which the firm performs engagements. Several commenters did not support inclusion of such a specified quality response. One commenter requested a requirement to design and implement controls to prevent unauthorized access to data and technology. The Board did not make any changes or additions to the quality objective or specified quality responses related to technological resources because it believes the more general provisions appropriately address this issue, and more specific provisions are at risk of quickly becoming outdated as technology evolves.

2. Current PCAOB Standards

QC 1000 largely covers the same areas addressed in QC 20 and QC 40 for personnel management and assignment of responsibilities.²⁶³ Existing PCAOB QC standards do not provide specific direction on the use of intellectual resources or technological resources, except for one application regarding independence.²⁶⁴

Information and Communication

This component addresses the firm's processes for obtaining, generating, sharing, and using information to enable the design, implementation, and operation of the QC system and the

performance of the firm's engagements, and for communicating information within the firm and to external parties.²⁶⁵ As discussed in more detail below, the Board made some changes in response to commenter input but adopted most provisions as proposed.

1. QC 1000

The information and communication area of the firm's operations serves the critical function of generating, gathering, and disseminating the information needed for the firm, including the QC system, to function. The process of determining information needs is iterative and ongoing; as the nature and circumstances of the firm change, information needs also change. The information and communication component of the QC system operates over this area of the firm's operations.

One firm suggested that the information and communication component refer to "relevant and reliable" information to convey that not all information is intended to be obtained and disseminated to the relevant individuals or roles. The firm disagreed that relevance and reliability is implied within the context of the proposed requirements, and argued that the term "information" needs parameters and qualifying language to provide boundaries to the vast amount of information that exists or could be created in the context of a firm's QC system. The firm further argued that without appropriate qualifiers, the breadth of information to be considered and/or communicated within a QC system will inhibit firm leaders from identifying and focusing on information most relevant to the successful operation of the QC system. As discussed in the proposal, in determining specific information to be communicated to firm personnel, including the nature and extent of such communication, the firm may consider the type of information that is relevant to the recipients given their roles and responsibilities within the firm. The Board continues to believe that information would have to be relevant and reliable to support the operation of the firm's QC system and the performance of the firm's engagements in accordance with applicable professional and legal requirements, so that a reference in the standard to "relevant and reliable" information is unnecessary.

²⁶¹ Evaluation of a firm's QC system is addressed in paragraphs .77–.78 of QC 1000 and discussed below.

²⁶² See, National Institute of Standards and Technology Glossary, available at <https://csrc.nist.gov/glossary>.

²⁶³ See QC 20.13 and .22.

²⁶⁴ See SECPS 1000.46 (requirement 4).

²⁶⁵ Other aspects of the standard also include specific provisions regarding communication (see, e.g., paragraphs 16–.17 in Roles and Responsibilities, and paragraphs .31 and .35 in Ethics and Independence).

a. Information and Communication Quality Objectives

The standard requires the firm to establish a number of quality objectives for the information and communication component. These objectives are discussed in more detail below. One firm commented that, as the proposed quality objectives for information and communication are broadly consistent with other jurisdictional and international quality control/management standards, they are appropriate, and no further changes are needed.

i. Identifying, Capturing, Processing, and Maintaining Information (QC 1000.53.a)

Identifying, capturing, processing, and maintaining information is an ongoing process necessary to support the firm's QC activities and the performance of its engagements in accordance with applicable professional and legal requirements. Information systems vary from firm to firm and encompass various sets of activities involving people, processes, data, or technology, or some combination thereof. Some firms' information systems may be heavily reliant on IT aspects while other information systems may require more manual intervention. Firms are able to determine the type of information systems necessary to achieve their quality objectives.

One commenter suggested that the information and communication component could be enriched by explicitly integrating academic audit and accounting studies as a vital source of information to be used by firms to inform their QC system. The Board believes that the quality objectives within the information and communication component sufficiently establish the desired outcomes for the identification of external information to support the operation of the firm's QC system. A firm may determine that the conclusions of certain academic studies inform the design or operation of its QC system. Furthermore, depending on the nature and circumstances of the firm and its engagements, the firm may consider any applicable academic studies in the firm's risk assessment process as it obtains an understanding of the conditions, events, and activities that may adversely affect the achievement of its quality objectives. The requirement was adopted as proposed.

ii. Exchange of Information (QC 1000.53.b–c)

Information is essential to firm personnel being able to understand and fulfill their responsibilities relating to the QC system and the performance of the firm's engagements. For example, through the Board's oversight activities, it observed improved audit quality when there was regular, consistent communication among members of the engagement team.²⁶⁶ The quality objective prompts firms to tailor the nature, timing, and extent of information communicated based on firm personnel's responsibilities, including those related to the firm's policies and procedures.

Communication is generally an ongoing process that involves all firm personnel. For example, the firm communicates information to engagement teams, such as information obtained during the firm's acceptance and continuance process that is relevant in performing the engagement. Engagement teams also communicate information to the firm—for example, information about the company obtained during engagement performance that may assist the firm when evaluating whether to continue the engagement. Two-way communication may also occur among firm personnel. For example, firm personnel performing engagements may exchange information directly with firm personnel performing activities within the firm's QC system, such as information to facilitate compliance with the firm's independence policies and procedures. The standard emphasizes the need for two-way communication within the firm and the responsibility of all firm personnel to communicate information.

One commenter addressed the quality objectives set out in paragraphs .53b–.53c. of the proposed standard related to the timely exchange of information between firm personnel and leadership, including those with responsibilities for the firm's QC system. The commenter recommended that the final release clarify that the firm's policies and procedures assist in promoting communication such that the appropriate individuals with responsibilities over the firm's QC system become aware of relevant matters in a timely manner, as appropriate for the size and the scale of the firm and relative nature of the matter. As discussed above, the Board believes timely communication and action should be sufficiently prompt to

achieve its objective and that timeliness is a function of the nature and significance of the issue. These requirements were adopted as proposed.

iii. External Parties (QC 1000.53.d–e)

There are many circumstances in which firms communicate information about themselves and their performance to external parties. Some external communications are required by law or regulation, such as the transparency reporting that is required in some jurisdictions, and others are made by firms voluntarily, for example, in connection with marketing or recruitment efforts.

The standard requires the firm to establish a quality objective that addresses communications to external parties in accordance with applicable professional and legal requirements. This quality objective focuses firms on providing the necessary communications to external parties when required. Among other things, this objective (paragraph .53d.) covers the completeness, accuracy, and timeliness of a firm's existing annual and periodic reporting to the PCAOB (*i.e.*, Forms 2 and 3, Form AP, and Form QC). It would also cover reporting under the Board's proposed revised reporting requirements and metrics requirements²⁶⁷ if those are ultimately adopted by the Board and approved by the SEC.

An investor expressed concern with the absence of references to investors or the public from the examples of external parties, and further commented that the proposal makes no mention of the role of quality control with respect to critical audit matters. This provision relates to communications to external parties that are required under applicable professional and legal requirements. Under current requirements, the only required communication from the audit firm to investors is the audit report. Audit reporting is part of engagement performance, is covered by a separate quality objective relating to engagement performance,²⁶⁸ and is not addressed by this quality objective. To the extent that a communication to a regulator is ultimately available to the public (as is the case with, for example, various forms filed with the PCAOB), such communications would be covered by this quality objective, thus providing

²⁶⁷ See PCAOB Rel. No. 2024–002.

²⁶⁸ See paragraph .42a.(3): “Responsibilities are understood and fulfilled . . . , including, as applicable . . . Responsibilities for reporting and other communications with respect to the engagement.”

²⁶⁶ See, *e.g.*, 2019 Inspection Observations Preview at 5.

downstream benefits for investors and the public.

A firm recommended that the scope of the requirement be limited to information or communications regarding a firm's audit practice and engagements performed in accordance with PCAOB standards. As discussed in more detail above, the definition of applicable professional and legal requirements in the final rule has been more narrowly tailored to address engagements, as defined in QC 1000, and the QC system itself. The Board believes this change addresses the commenter's concern about the possible overbreadth of the quality objective, and the Board adopted it as proposed.

The PCAOB also observed that some firms make public communications about firm-level or engagement-level information, such as firm metrics and financial data. For example, some firms publish transparency or audit quality reports, either voluntarily or in response to the requirements of other jurisdictions, that contain data such as:

- Revenue breakdown by service line, by year, or by geographic segment;
- Professional staff ratios;
- Staff turnover ratios;
- Average training hours per professional; and
- Partner workload.

In addition to transparency or audit quality reports, firms may communicate these data via web pages or other media, such as promotional publications, social media, interviews, or presentations via webcast or video. Furthermore, if adopted, the Firm and Engagement Metrics proposal will require firms to publicly report certain metrics relating to their audits and their audit practices.

Regardless of the form of communication and the type of information presented, the Board believes that firms' QC systems should address the integrity of firms' external communications about themselves and the performance of their engagements. Such information can influence the views of relevant stakeholders, including audit committees determining whether to engage or retain an auditor and investors determining whether to ratify such an appointment.

The proposed standard contemplated that the firm would establish a specific quality objective that firm-level or engagement-level information communicated externally is accurate and not misleading and, with respect to any performance metrics, that the communication explains in reasonable detail how the metrics were determined and, if applicable, how the metrics or the method of determining them changed since performance metrics

were last communicated. The Board's view is that a specific quality objective in this area will prompt firms to implement targeted policies and procedures that address, for example, the quality and consistency of data and the need for context or explanation. This in turn will improve the informativeness, reliability, and comparability of such communications and avoid misleading the intended audience.

Several commenters, including firms and related groups, broadly supported the quality objectives or agreed that it is important to address communications to stakeholders about a firm's or engagement's performance, and that such communications should be accurate and not misleading. However, many of the commenters on this topic raised concerns with regard to the proposed quality objective addressing the firm's external communications relating to metrics.

Several commenters suggested that additional clarification be provided on the metrics and communications that are in scope for the quality objective. Some commenters recommended that the scope of the requirement be limited to metrics related to audit quality that are required to be communicated under applicable professional, legal, or other regulatory requirements and are communicated publicly. One firm recommended that the scope of metrics be limited to those related to the effectiveness of the firm's QC system or audit quality, and that the scope of the communications be limited to "formal" external reporting such as audit quality reports, transparency reports, communications with audit committees, and other published reports. Another firm recommended that the external communications in scope for the objective should be limited to communications externally about audit quality and should not extend to other external information issued by the firm that is not specifically related to audit quality such as marketing communications or recruiting information. The firm further argued that this limitation on scope to only audit-quality-related external communications should also apply to the communication of how metrics were determined and explanations of year-on-year changes. Another firm recommended that the scope be limited to information or communications regarding a firm's audit practice and engagements performed in accordance with PCAOB standards.

One firm expressed concern regarding firms' ability to design and implement quality responses to address the risk of

every type and form of information communicated given the broad scope of the requirement. The firm recommended that the scope should be limited to information resulting from and regarding the evaluation of the firm's QC system, which will allow firms to focus efforts on the information that is most meaningful to stakeholders, which in turn will enhance the reliability of such information.

One firm commented that in addition to recommending limiting the quality objective to engagements performed under PCAOB standards that would be subject to the firm's QC system, it may not be practicable to communicate in reasonable detail how a metric was determined in all situations (*e.g.*, if the metric was provided in a speech). The firm asserted that it should be allowed to present the information about how a metric was determined and, if necessary, how it changed, in a single, publicly available location (*e.g.*, on the firm's website). One firm commented that the level of disclosure that would be required may create confusion or may not ultimately be necessary, in particular in instances when the metric does not relate to audit quality. Further, the firm stated that the disclosures may conflict with requirements that may apply to registered firms outside of the U.S. Another firm recommended that the words "explains in reasonable detail how the metrics were determined and, if applicable, how the metrics or the method of determining them changed since performance metrics were last communicated" be removed from the quality objective. The firm asserted that this requirement may discourage smaller firms from including many quality metrics in their audit quality, transparency, and similar reports given limited time and resources available to produce their voluntary report. Some commenters, including firms and a related group, recommended that considerations related to metrics in QC 1000 be taken up as part of the PCAOB's research project on firm and engagement performance metrics.

After consideration of the comments received, the Board continues to believe it is appropriate that all firm communications to external parties regarding themselves and their audit practice, in whatever medium, meet the minimum standard of being accurate and not misleading.

However, in response to commenters, the Board clarified the quality objective in certain respects. It has clarified that the quality objective is limited to communications regarding the firm's audit practice, firm personnel, or engagements and removed the word

“performance” from the phrase “performance metrics,” to align with the terminology use in the Board’s proposed metrics requirements.²⁶⁹ Additionally, the Board revised the quality objective to provide that only metrics communicated in writing require an explanation of how the metrics were determined and, if applicable, how the method of determining them changed since metrics were last communicated. The Board believes this will address commenter concerns about the feasibility of providing such explanations for metrics communicated orally. In addition, the Board removed the requirement to explain in reasonable detail, if applicable, how the metrics themselves have changed since they were last communicated. The Board believes that requiring an explanation of how the metrics were determined and, if applicable, how the method of determining the metric changed since it was last communicated will enhance the understandability and comparability of the metrics made available to external parties. However, the Board does not believe it to be necessary to require narrative discussion of numeric changes in the metric period over period if there has been no change in the underlying calculation method.

These disclosures may be incremental to requirements that could apply to registered firms outside of the U.S., however, the Board does not believe that these requirements will operate in conflict. The Board has observed variation and complexities in how metrics are defined and calculated by firms, as well as changes in the calculation method over time such that it believes this quality objective is necessary to improve the informativeness, reliability, and comparability of such communications and avoid misleading the intended audience. In addition, over 100 unique qualitative disclosures and quantitative audit quality metrics have been observed by the Center for Audit Quality (“CAQ”) in its analysis of the CAQ’s eight Governing Board firms’ most recent audit quality reports.²⁷⁰ The Board believes this indicates both a demand for and an ability to supply metrics, which further emphasizes the need for consistency and comparability of the metrics.

The Board considered whether it would be appropriate to allow for additional disclosures relating to metrics to be presented in a single

public location such as the firm’s website. However, the Board believes that by limiting the requirement to written communications, it has eliminated the concern about how to present such information with respect to an oral communication, and given the importance of the information to the intended audience, that this should be presented in the same written communication as the disclosed metrics.

The Board received feedback from a number of commenters, including investors and related groups, criticizing the proposal for failing to include required metrics or audit quality indicators. The Board has proposed a separate standard on firm and engagement metrics²⁷¹ and it has addressed these comments in that proposal.

iv. Networks (QC 1000.53.f)

If the firm belongs to a network, exchange of information between the firm and the network may play an important role in supporting the operation of the firm’s QC system and the performance of its engagements. For example, if the network performs certain monitoring activities relating to the firm’s QC system, the network’s communication of information (*e.g.*, results of its monitoring activities or any changes to its activities from the prior year) may result in the firm adjusting the nature, timing, and extent of its own monitoring activities. On the other hand, the firm may need to communicate to the network when there are changes to the firm’s QC system that may affect the network’s monitoring activities.

The Board did not receive comment on the proposed quality objective relating to the exchange of information between a firm and a network and adopted it as proposed.

v. Other Participants (QC 1000.53.g–h)

Many firms have increasingly involved parties outside the firm in QC functions, such as independence compliance, and engagement functions, such as performing audit procedures and evaluating audit evidence. Working with other participants can differ from working with individuals within the firm. For example, auditor-engaged specialists²⁷² may have different professional training and experience

and may operate under a different type of QC system, or none at all. Firms may experience differences in local norms and expectations when working with firms based in other jurisdictions. These and other factors give rise to risks in the communication between firm personnel and other participants, including the potential for misunderstandings regarding the audit effort needed to meet the objective of the other participant’s work.²⁷³ It is therefore imperative that appropriate communications take place between the firm and other participants to enable the other participants to understand and carry out their responsibilities relating to activities within the firm’s QC system and the performance of its engagements in accordance with applicable professional and legal requirements and the firm’s policies and procedures.

The Board broadened the language of the quality objective to clarify that it applies to the use of participants in both the firm QC system and in engagements.

For other participants that are firms, the Board proposed that information obtained from the other participants should include the conclusion of the most recent evaluation of its QC system and a brief overview of remedial actions taken and to be taken, as well as a footnote clarifying that the most recent evaluation of the other participant firm’s QC system refers to that firm’s evaluation under paragraph .77 of QC 1000 as of the most recent evaluation date, if such an evaluation was performed, and otherwise to the most recent QC evaluation performed by the other participant firm under any professional standard.²⁷⁴

One commenter stated that audit firms monitor the quality of member firms but have typically been reluctant to share negative information about a member firm, and that requiring transparency in such information would be beneficial. However, several firms and related groups expressed concerns about the impact of having other participant firms share the most recent evaluation of their QC system based on the confidentiality protections set out in Sarbanes-Oxley or other relevant local laws and regulations. Two firms commented that these concerns would be alleviated if the definition of QC deficiency was updated to align with the definition in ISQM 1 and SQMS 1. One firm commented that the proposed quality objective addressing information and communication related to other participants is appropriate, however if

²⁷¹ See PCAOB Rel. No. 2024–002.

²⁷² AS 1210, establishes requirements regarding the use of a specialist engaged by the auditor’s firm (“auditor-engaged specialist”) to assist the auditor in obtaining or evaluating audit evidence with respect to a relevant assertion of a significant account or disclosure.

²⁷³ See, *e.g.*, PCAOB Rel. No. 2022–002.

²⁷⁴ See, *e.g.*, ISQM 1 paragraphs .53–.54; and SQMS 1 paragraphs .54–.55.

²⁶⁹ See PCAOB Rel. No. 2024–002.

²⁷⁰ See Audit Quality Reports Analysis: A Year in Review, available at <https://www.thecaq.org/aqr-analysis-yir/>.

information is to be shared at the deficiency level, the firm is concerned that this would violate the confidentiality provision within Sarbanes-Oxley. Another firm suggested limiting the extent of information shared to only what is necessary for firms to achieve the reasonable assurance objective. This firm agreed with obtaining and considering the other participant firm's overall conclusion of the most recent evaluation of the QC system, however it argued that this should not include information regarding deficiencies, if any, and remedial actions taken and to be taken. Some commenters argued that firms should be able to take a risk-based approach in determining whether it is necessary to request specific information regarding an other participant firm's QC system.

One firm-related group argued that certain international legislation may be an issue for firms when reporting clients' or individuals' personal information. The commenter further expressed concerns that those firms applying QC 1000 fully and reporting thereunder may be selected in preference to those using other standards. Another firm-related group expressed concern that a firm-level QC inspection finding might result in the best firm for the component auditor role being bypassed. The commenter further suggested that guidance is needed for when the evaluation and/or overview of remedial actions is not forthcoming.

Some commenters, including firms and a related group, argued practical concerns regarding the application of the requirement to other participants not registered with the PCAOB. One firm commented that, while it is not aware of any legal or regulatory concerns with other participants sharing the most recent evaluation of their QC system, it suggested that the PCAOB state that firms will not violate this requirement if local laws or regulations exist that prevent compliance.

After consideration of the comments received, the Board amended the standard to limit the information that should be obtained to only the conclusion of the most recent evaluation of the QC system. The Board believes that this addresses commenter concerns relating to the risk of communicating privileged information. Furthermore, the Board continues to believe that obtaining the communication of the conclusion of the other participant's most recent evaluation may assist a firm in determining the nature and extent of supervision of the work of other participants or deciding whether other participants are fit to participate in the

firm's engagements, including ensuring that the best firm for the job is not bypassed. If necessary, the firm may discuss the conclusion with the other participant firm to seek to gain a better understanding of the basis for such conclusion.

The Board believes that in practically all cases, the firm would be able to obtain the conclusion of the most recent evaluation of the other participant's QC system. However, if a firm is unable to obtain this (for example, if the other participant has not performed an evaluation, or if local laws forbid them from sharing it), then the firm should assess what other procedures are necessary to achieve the quality objective.²⁷⁵

One firm commented that paragraph 53f. specifically addressed networks, while .53g. addresses other participants, and that it was unclear whether paragraph .53g. also applies to networks given their inclusion in the definition of "other participants" or if the Board intends for paragraph .53g. to apply to any other party defined within "other participants." Paragraph .53g. applies to firms within a network to the extent that the firm is an other participant, as defined in QC 1000.A7 and discussed in more detail above.

Another firm expressed concerns that it may not be able to practically apply paragraph .53g. to all "other participants." Specifically, the firm requested clarification as to the expectation regarding the extent to which firms design policies and procedures to ensure other participants comply with applicable professional and legal requirements, including bifurcation of participants that are part of the engagement team as compared to participants in the firm's quality control system. Another firm suggested it would be impractical to suggest that a firm's QC system can be applied to other participants or that they would explicitly comply with the firm's policies and procedures as if they were part of the firm. As discussed in more detail above, just because a quality objective or other provision of QC 1000 refers to all types of other participants in the same way, this does not mean that the firm should respond by treating all types of other participants in the same way. The firm's policies and procedures addressing other participants should differentiate based on the types and roles of other participants to the extent necessary to be responsive to the firm's quality risks (for example, the firm would have

different policies for the use of engaged specialists versus external EQRs).

The proposed requirement in paragraph .53.h did not draw comment and was adopted as proposed.

The firm may also participate in another firm's engagement as an other participant. For the same reasons that apply when the firm is issuing the engagement report and using the work of other participants, it is important that there is an appropriate exchange of information in order to enable the firm serving as an other participant to fulfill its role in accordance with applicable professional and legal requirements.

d. Information and Communication Specified Quality Responses (QC 1000.55–.56)

One firm commented that the proposed specified quality responses for information and communication are appropriate. Other comments that are specific to each specified quality response are discussed below.

The requirement in paragraph .55 carries forward an existing requirement from the PCAOB's QC standards and extends it to cover other participants, not just firm personnel.²⁷⁶ One firm suggested that, as it relates to other participants, the quality objective in paragraph .53g. was sufficient, and the specified quality response was not needed. Another firm commented that it is concerned that expanding the requirement to communicate quality control policies and procedures beyond firm personnel to include other participants may not be operational due to the size, content, and methods of accessing the policies and procedures. The firm further asserted that the proposed standard may inappropriately blur the lines between a firm's system of quality control and engagement-level requirements that are already addressed through existing PCAOB standards and rules. The Board believes that other participants play an important role in the operation of the firm's QC system and the performance of its engagements and that it is imperative for these other participants to be aware of the firm's policies and procedures to the extent required to enable them to carry out their responsibilities. For that reason, the Board believes it is necessary to expand the existing requirement to include other participants in a specified quality response.

To address the concern about the volume of material required to be shared with other participants, the Board clarified the requirement by providing that policies and procedures should be

²⁷⁵ See PCAOB Rule 3101(a)(2).

²⁷⁶ See QC 20.23.

communicated “to the extent” and in a manner reasonably designed to enable firm personnel and other participants to carry out their responsibilities; in other words, the requirement is to communicate what firm personnel and other participants need to know, not necessarily all of the firm’s policies and procedures. For example, a firm would communicate to an EQR contracted by the firm its policies and procedures related to EQR review and independence. In addition, although the wording of the requirement is different, the substance of the existing requirement²⁷⁷ is unchanged. Reference to “reasonably designed and implemented” captures the existing requirement to communicate in “a manner that provides reasonable assurance that those policies and procedures are understood and complied with” without repeating the reasonable assurance already captured by the overarching objective of the QC standard.

Another commenter requested clarification as to whether the communication of policies and procedures is required in narrative, flowchart, or other form. The Board believes that the policies and procedures should be in writing and in a manner that is reasonably designed to enable firm personnel and other participants to understand and carry out their responsibilities relating to activities within the firm’s QC system and the performance of its engagements. The format of these policies and procedures may vary depending on the specific responsibilities being addressed and how the firm wants to communicate them.

Under the existing PCAOB standard, the firm is also required to make timely communications to appropriate personnel regarding changes to its established quality control policies and procedures. The Board does not think it is necessary to address changes to policies and procedures separately; the requirement is to communicate policies and procedures as in effect, which includes changes to such policies and procedures over time. If the firm needs to communicate changes to its policies and procedures to enable firm personnel and other participants to understand and carry out their responsibilities, then the specified quality response will require such communication.

Given the importance of information generated from the monitoring and remediation process, paragraph .56 includes a specified quality response that requires the firm to communicate

such information to firm personnel to enable them to take timely action. In determining specific information to be communicated to firm personnel, including the nature and extent of such communication, the firm may consider the type of information that is relevant to the recipients given their roles and responsibilities within the firm. For example, information communicated to engagement teams may be focused on a description of identified engagement deficiencies and related remedial actions that are likely to be relevant to such firm personnel and their engagements. Information communicated to all firm personnel may relate to deficiencies identified through QC system-level monitoring activities, such as compliance issues in connection with the firm’s ethics and independence policies and procedures.

One firm asserted that the requirement to communicate identified engagement deficiencies and QC deficiencies to firm personnel could hold firms to a higher standard than may be prudent, and that a perceived requirement to communicate each engagement deficiency seems imbalanced to appropriately influence change. The specified quality response requires that such communications be made to enable firm personnel to take timely action in accordance with their responsibilities. Based on the results of the monitoring and remediation process, the firm can assess the nature and extent of the communications to be made, and this should be commensurate with the risk that other similar unidentified engagement deficiencies exist; for example, for engagement deficiencies related to the examination of broker-dealer compliance reports, the firm may limit the communications to firm personnel working on broker-dealer engagements and adjacent industry sectors.

In addition, under paragraph .57 the firm is required to communicate the results of the annual evaluation of its QC system to certain individuals in firm leadership positions. These individuals may use this information in various ways, for example, as a basis for further communications to firm personnel about the importance of quality or to address concerns about the QC system in a timely manner. The requirement reinforces firm leadership’s responsibility and accountability for the firm’s QC system.

2. Current PCAOB Standards

Existing PCAOB QC standards focus principally on communication of certain information, specifically:

- Firm QC policies and procedures;²⁷⁸
- Weaknesses identified in the QC system or the level of understanding or compliance therewith;²⁷⁹
- Internal inspection findings;²⁸⁰
- Principles that influence the firm’s policies and procedures on matters related to the recommendation and approval of accounting principles, present and potential client relationships, and the types of services provided;²⁸¹
- Additions to the Restricted Entity List;²⁸² and
- Notification to the SEC of resignations and dismissals from audit engagements for SEC registrants.²⁸³

QC 1000, by contrast, more broadly addresses the firm’s responsibilities regarding its information system and internal and external communications.

Monitoring and Remediation Process

1. QC 1000

a. Overview (QC 1000.58)

The monitoring and remediation process is an integral part of an effective QC system because it creates a feedback loop to inform the firm’s risk assessment process. The feedback loop will help the firm identify and assess new and evolving quality risks and design and implement effective quality responses. It drives a firm’s focus on continuing to improve its QC system, with a view to preventing future engagement deficiencies. The monitoring and remediation process applies to the design, implementation, and operation of all QC system components, including the monitoring and remediation component, and provides the basis for a firm’s evaluation of whether its QC system is effective and for reporting on the QC system.²⁸⁴

The Board has observed through its oversight activities that some firms have made significant efforts to enhance their monitoring and remediation process, which has led to improvements in the firms’ QC systems and in audit quality. These efforts include increased attention to ongoing monitoring activities, internal monitoring of both in-process and completed engagements,

²⁷⁸ See QC 20.23.

²⁷⁹ See QC 30.03.

²⁸⁰ See QC 30.06.

²⁸¹ See SECPS 1000.08(l), 1000.42.

²⁸² See SECPS 1000.46 (requirement 5).

²⁸³ See SECPS 1000.08(m); see also Appendix 5 for a proposed new standard, AS 1310, *Notification of Termination of the Auditor-Issuer Relationship*, that would retain existing requirements of SECPS 1000.08(m) and apply those requirements to all firms.

²⁸⁴ For further discussion of the evaluation of a firm’s QC system, see below.

²⁷⁷ See QC 20.18.

root cause analysis of both positive outcomes and QC deficiencies, and remedial actions to address QC deficiencies. However, PCAOB inspections continue to identify deficiencies for some firms, suggesting that not all firms have made meaningful improvements in these areas.

Under QC 1000, the monitoring and remediation process addresses the following:

- General requirements;
- Engagement monitoring activities;
- QC system-level monitoring activities;
- Monitoring activities performed by a network;
- Determining whether engagement deficiencies exist;
- Responding to engagement deficiencies;
- Determining whether QC observations exist;
- Determining whether QC deficiencies exist;
- Responding to QC deficiencies; and
- Monitoring the implementation and operating effectiveness of remedial actions.

Under the standard, a firm performs monitoring activities to determine whether its quality responses are properly designed and operating as intended, such that the firm's quality risks are sufficiently mitigated and its quality objectives are achieved. As described later, the results of the firm's monitoring and remediation process are to be evaluated annually as part of the evaluation of the QC system. Therefore, the monitoring activities conducted need to be sufficient to support the conclusions reached during such an evaluation.

b. General Requirements (QC 1000.59–.61)

The standard specifies three goals for the monitoring and remediation process:

- *Relevant, reliable, and timely information.* Monitoring and

remediation must provide information about the design, implementation, and operation of the firm's QC system that is relevant, reliable, and timely. The information obtained from monitoring activities informs a firm about actions, behaviors, or conditions that contributed to issues that need to be addressed and may also provide insights as to factors that help prevent deficiencies from occurring. For example, information obtained about actions, behaviors, and conditions related to an engagement that was subject to internal or external monitoring activities where no deficiencies were identified may provide insights about good practices to use when addressing issues on similar engagements.

- *Reasonable basis for timely detection of engagement deficiencies and QC deficiencies.* The standard uses the concept of “reasonable basis,” which is present throughout PCAOB auditing standards, including the standards governing the auditor's report.²⁸⁵ Therefore, this concept is well understood by the profession. “Timely” as it relates to the detection of engagement deficiencies means that the firm's monitoring activities are designed to identify deficiencies as promptly as practicable. For example, the Board expects that the firm's monitoring activities will generally enable the firm to identify deficiencies in calendar year-end engagements in time to include them in its evaluation of the QC system as of the following September 30.

- *Timely remediation.* The firm's monitoring and remediation process must enable timely remediation of identified engagement deficiencies and QC deficiencies. What constitutes

“timely” depends on the deficiency's nature, scope, and impact. For example, where there is a high risk of severity or pervasiveness, remedial actions may have to be immediate to be timely.

The first element of monitoring and remediation is designing and performing monitoring activities for engagements and the QC system itself. The Board believes that the selected frequency and timing of the firm's monitoring activities (e.g., a combination of ongoing and periodic monitoring activities) are important elements in achieving an overall effective monitoring and remediation process. Ongoing monitoring activities are generally those activities that are routine in nature, built into the firm's processes, and performed on a real-time basis. Periodic monitoring activities, by contrast, are conducted from time to time at set intervals. The use of ongoing and periodic monitoring activities would vary by firm and be influenced by the nature and circumstances of the firm.

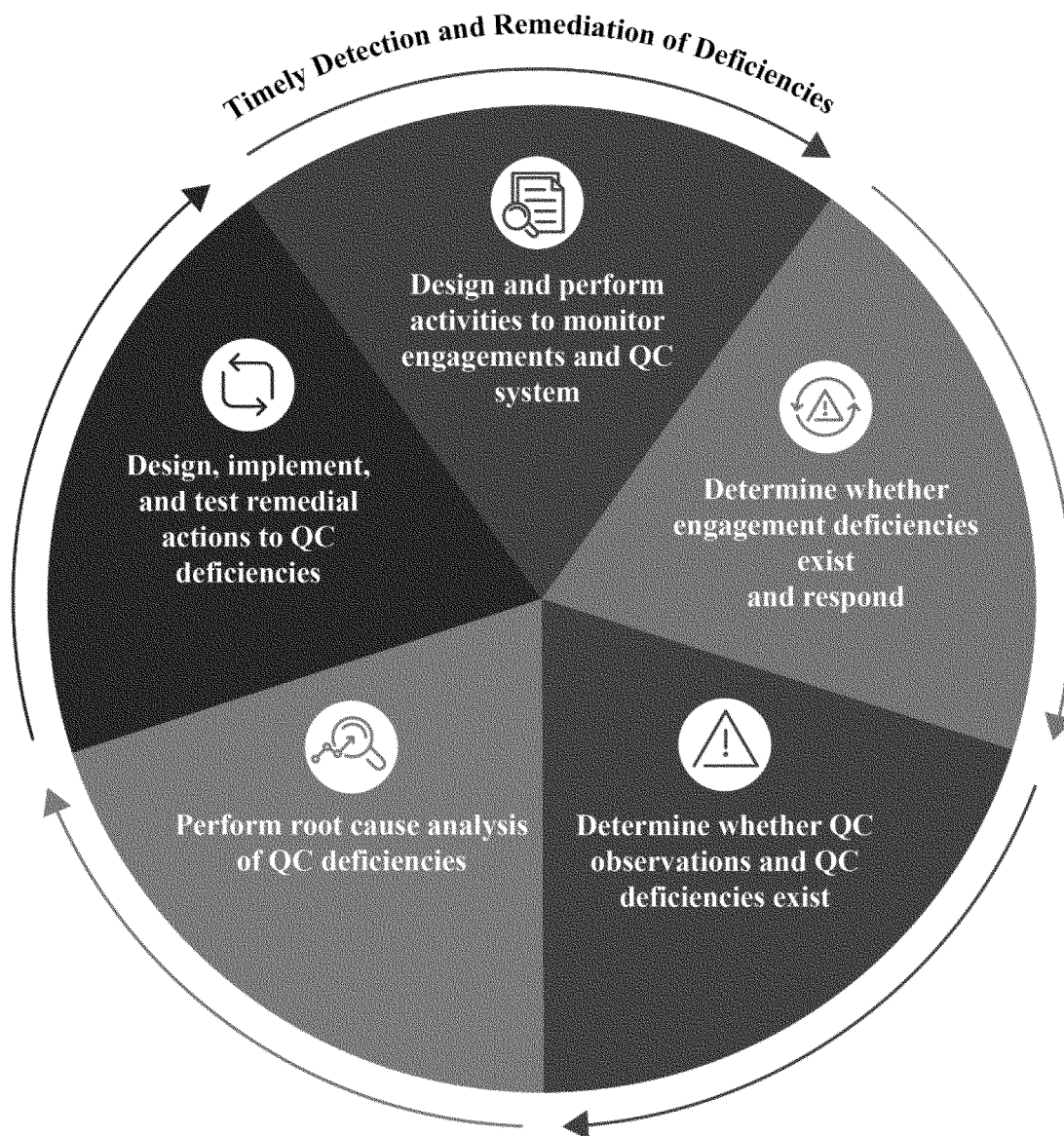
The other elements of the monitoring and remediation process specified in the standard are:

- Determining whether engagement deficiencies exist and responding to them.
- Determining whether QC observations exist.
- Determining whether QC deficiencies exist.
- Performing root cause analysis of QC deficiencies.
- Designing and implementing remedial actions to respond to QC deficiencies and determining whether such actions are implemented as designed and operate effectively.

These other elements are discussed below, in relation to the requirements of paragraphs .61–.76.

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²⁸⁵ See, e.g., AS 3101.09f (noting that one of the elements in the Basis for Opinion section of the auditor's report is “[a] statement that the auditor believes that the audit provides a reasonable basis for the auditor's opinion”).

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QC 1000 requires that the firm's QC system include both engagement monitoring activities and QC system-level monitoring activities. The standard differentiates engagement monitoring activities from QC system-level monitoring activities. The two types of activities would provide different kinds of information and, in the Board's view, a firm would need both in order to have a reasonable basis for detecting engagement and QC deficiencies and evaluating its QC system. Engagement monitoring activities are monitoring procedures performed on engagements, including in-process and completed engagements. QC system-level monitoring activities are monitoring procedures regarding aspects of a firm's QC system, including the firm's risk assessment and monitoring and remediation processes.

Notwithstanding the differences between engagement monitoring activities and QC system-level monitoring activities, a firm could design and perform dual-purpose monitoring activities—*i.e.*, activities directed at individual engagements that also address aspects of the firm's QC system. For example, a firm could perform engagement monitoring activities related to acceptance and continuance of engagements that would also address the design, implementation, and operation of the acceptance and continuance of engagements component of the firm's QC system.

QC 1000 defines "engagement" as any audit, attestation, review, or other engagement performed under PCAOB standards (1) led by a firm or (2) in which a firm plays a substantial role in the preparation or furnishing of an

engagement report. Under the standard, substantial role engagements that the firm undertakes would be required to be included in the population of engagements on which the firm performs monitoring activities. In situations where the firm participates in another firm's engagement but does not play a substantial role, while such work would not be treated as the firm's own "engagement" for purposes of the standard, any firm that was required to implement and operate an effective QC system under the standard is required to extend its QC system to all audit, attestation, review, and other work it performs under PCAOB standards, including other firms' engagements in which the firm plays less than a substantial role.

In general, for purposes of QC 1000, engagement monitoring activities are performed only on "engagements" as

that term is defined in the standard. One firm suggested that audit quality should consistently be measured for all engagements, whether performed under the PCAOB standards or other auditing standards, and therefore a firm's QC system should provide reasonable assurance of performing all such engagements in compliance with applicable laws and professional requirements. This firm urged the Board to consider whether the monitoring-related requirements in QC 1000 that use the term "engagements" (as defined in QC 1000) may result in a lost opportunity to fully capitalize on the expected benefits of a more comprehensive monitoring program. Given the limits of the Board's statutory authority under Sarbanes-Oxley, the Board does not believe it would be appropriate to expand the scope of the term "engagements" to include work performed under standards of other standard-setters. However, nothing prevents firms from developing a single QC system for their entire audit practice that satisfies both PCAOB requirements and other professional standards to which the firm is subject, which could include performing the same types of monitoring activities for both PCAOB engagements and other audits.

The Board also understands that firms that perform only a small number of issuer and broker-dealer engagements would be significantly affected by a requirement to perform monitoring activities over PCAOB "engagements" every year.²⁸⁶ In the extreme case, a firm that issues an audit report for only one issuer would have to monitor the same engagement every year. The prospect of annual monitoring could disincentivize partners from serving as the engagement partner and ultimately affect competitive conditions in the market. Accordingly, paragraph .61a includes a note that permits firms that issued engagement reports for five or fewer issuers, brokers, and dealers in the previous year to include audits not performed under PCAOB auditing standards in their engagement monitoring activities for purposes of QC 1000, so long as the audits are selected taking into account the factors in determining the nature, timing, and extent of engagement monitoring activities set forth in paragraph .64. This accommodation takes into consideration the structure of the SEC's partner rotation requirements exemption for

small firms,²⁸⁷ and is limited to audits rather than attestation work because audits are performed under more rigorous standards. These firms will still have to design, implement, and operate a monitoring and remediation process that meets the requirements of QC 1000, including the requirements regarding the objectives and elements of the monitoring and remediation process set forth in paragraphs .59 and .60, which focus on "engagements" as defined in the standard. The firms will also be subject to the requirement under paragraph .62b to inspect at least one completed PCAOB engagement for each engagement partner on a cyclical basis, as discussed below.

Current PCAOB QC standards provide that, in some circumstances, individuals may perform monitoring procedures over the same areas for which they are responsible.²⁸⁸ Such monitoring procedures are a type of self-assessment and under the proposed standard, self-assessments would not have been permissible. Individuals would lack the requisite objectivity if they reviewed engagements in which they participated (or, in the case of audits, for which they performed the engagement quality review), or monitoring activities for which they participated in the design, implementation, or operation of the activity.

Two commenters agreed that self-assessment should not be permitted in QC 1000. Other commenters, including firms and a related group, raised concerns regarding the proposal's disallowance of self-assessments as part of a firm's monitoring and remediation process. Specific concerns included the impact of this requirement on smaller firms and the resource constraint that may be very difficult for firms to overcome if individuals who may be involved in an engagement through consulting with engagement teams, evaluating engagement team progress, or monitoring turnover on the engagement team are ineligible to perform monitoring activities.

While the Board appreciates the concerns around resource constraints raised by commenters, allowing individuals to review their own work is inconsistent with the quality objective in paragraph .44e that individuals assigned to perform activities within the QC system have the objectivity needed to perform such activities in accordance with applicable professional and legal requirements and the firm's policies and

procedures. Taking into account commenter feedback, the Board added a note to the standard to clarify that the restriction on self-assessment is grounded in that quality objective. The note further explains the implication, in the context of the monitoring and remediation process, that individuals generally cannot perform monitoring activities over their own work, for example by performing engagement monitoring activities on an area of an engagement in which they participated. The impact of this restriction will depend on the role that the individual played in the engagement. For example, individuals who have consulted on a particular area of an engagement would be permitted to perform monitoring activities on other areas of an engagement that were unrelated to the consultation. However, individuals that served as the engagement quality reviewer on an engagement may not perform monitoring activities on that engagement, even if they did not review every area of the engagement.

e. Engagement Monitoring Activities (QC 1000.62–.64)

Engagement monitoring activities provide valuable information to firms on whether engagement or QC system-level areas may require additional attention. For example, monitoring procedures may highlight an area on an audit engagement where insufficient audit evidence was obtained to support the auditor's opinion. More broadly, engagement monitoring activities may identify pervasive issues where a number of engagements have similar problems, possibly highlighting the need to revise methodology, provide additional training, or take other actions at the QC-system level.

i. Monitoring Completed Engagements (QC 1000.62)

Similar to the proposal, the final standard requires firms to perform engagement monitoring activities on completed engagements. Two commenters expressed support for the requirement to monitor completed engagements. One commenter suggested that paragraph .62 be amended to permit the legacy flexibility of QC 20 for a firm to have pre-issuance or post-issuance, or both, monitoring programs, depending on the individual firm's risk assessment. This commenter asserted that some smaller firms, in particular, have already implemented robust pre-issuance quality monitoring reviews on substantially all issuer audits.

The Board continues to believe that the information derived from performing inspections of completed

²⁸⁶ Firms that issued audit opinions for between one and five issuers or broker-dealers represented 38% of all registered firms in 2022, 39% in 2021, and 43% in 2020.

²⁸⁷ See 17 CFR 210.2–01(c)(6)(ii).

²⁸⁸ See QC 30.10, which applies to small firms with a limited number of management-level individuals.

engagements provides the firm a perspective on its engagements that cannot be obtained through other monitoring activities. The Board also noted that the standard does not prescribe specific monitoring activities, so firms will be able to determine what activities to perform when monitoring completed engagements. Based on PCAOB oversight activities, the Board has observed that most firms perform engagement monitoring activities on their completed engagements as part of their existing QC practices. Requiring the inspection of completed engagements would therefore not change practice for most firms and, accordingly, seems unlikely to impose incremental costs in most instances.

The proposed standard also included a requirement for firms to establish a cyclical basis for monitoring completed engagements such that each engagement partner would have at least one engagement subject to monitoring in each cycle. Some firms and a related group supported that requirement in principle. Some commenters suggested that firms should be permitted to include all of the engagements within a particular engagement partner's portfolio of engagements, not only PCAOB engagements, since the firm operates a single QC system. One commenter stressed that if firms are not permitted to consider all engagements in an engagement partner's portfolio, it may unnecessarily drive firms to two separate cyclical inspection programs (that is, doubling inspection program activities) based on the applicable set of professional standards. This commenter also suggested that the standard should allow firms to consider whether engagement partners have been subjected to external inspections/reviews when determining if, and when, to subject them to an internal inspection.

Similar to the proposal, the final standard requires firms to inspect at least one completed PCAOB engagement for each engagement partner over a cyclical period. Although, as discussed above, firms with five or fewer issuer and broker-dealer engagements may be permitted to include non-PCAOB engagements in their monitoring activities, inspections under this paragraph must be of "engagements" as defined in QC 1000. This will ensure that firms regularly evaluate the work of every partner under PCAOB standards to determine whether engagement deficiencies or QC deficiencies have occurred and can design and implement appropriate remedial actions. The note to the final standard clarifies that point.

The proposed standard also included a note stating that if a firm uses a cycle longer than three years, the firm would be required to demonstrate how its cycle is adequate to provide the firm with a reasonable basis for detecting engagement deficiencies and QC deficiencies, taking into account the factors in paragraph .64. Several commenters, including an investor-related group, disagreed with this aspect of the proposal, suggesting that each firm should be allowed to determine the appropriate cycle for engagement partner selection. Some of these commenters stated that requiring a set interval for engagement partner selection could actually result in a reduced ability by the firm to incorporate unpredictability into the selection process. One firm further stated that the proposed requirement regarding the engagement partner selection cycle could also decrease the frequency of other monitoring activities, such as in-process reviews, or curb investment and innovation in pre-issuance monitoring programs.

The Board continues to believe it is appropriate to incorporate an expectation that each engagement partner will be subject to inspection at least every three years and adopted that aspect as proposed. A three-year period appears to be a norm for other standard setters and, based on PCAOB oversight activities, is common in practice.²⁸⁹ The Board appreciates that requiring a set interval could make the timing of selection predictable for an engagement partner, so a three-year cycle is a baseline expectation, not a requirement. Firms can of course adopt a shorter cycle, or can adopt a longer cycle if they are able to demonstrate how that cycle is adequate to provide a reasonable basis for detecting engagement deficiencies and QC deficiencies. Regardless of the cyclical period used by the firm, risks or other circumstances related to an engagement or an engagement partner may trigger the need for the firm to inspect an engagement partner's completed engagement(s) more than once during the cyclical period.

The proposed note to paragraph .62b also included language requiring firms to consider incorporating a level of unpredictability when determining when, during the cyclical period, an engagement partner has an engagement selected for monitoring and which completed engagement(s) to select. This

was intended to make it less likely that engagement partners would be in a position to manage engagements with the expectation that they would or would not be inspected. However, commenters, including firms and investors and related groups, suggested that this language should be strengthened to require that the firm "should" incorporate unpredictability into the selection process. One of these commenters went further to suggest that the PCAOB also incorporate language requiring unpredictability in the focus areas subject to internal inspection monitoring, in addition to the timing of such monitoring. The Board agreed with the comments raised with respect to requiring firms to incorporate unpredictability into their selection process and this change is reflected in the note to paragraph .62b. Additionally, in order to allow sufficient flexibility for firms to determine how to incorporate unpredictability in the selection process, language has been added to the note to clarify that the firm should include an element of unpredictability in "at least one of" the elements listed in the note to paragraph .62b.

The firm's selection of completed engagements should be responsive to information obtained from various sources, including prior monitoring activities. The standard, in paragraph .64 (discussed further below), includes factors for a firm to take into account when selecting engagements for monitoring. These factors will assist a firm when determining its cyclical basis and selecting at least one engagement to inspect for each engagement partner.

ii. Monitoring In-Process Engagements and Other Work (QC 1000.63)

Monitoring in-process engagements can help firms detect and prevent potential engagement deficiencies before an engagement report is issued, resulting in a more proactive, preventive monitoring approach. Through its oversight activities, the PCAOB has observed a variety of different in-process engagement monitoring activities, including:

- Monitoring activities on a specific area of the audit after the engagement team has conducted certain audit procedures or used a specific tool or template (e.g., an in-process reviewer evaluates an engagement team's testing of management's earnings forecast used in an impairment analysis);
- Engagement team coaching by an individual who is not part of the engagement team (e.g., a member of the firm's national office works with an engagement team to review their audit

²⁸⁹ The application material accompanying the IAASB and AICPA QC standards provide an example of a three-year inspection cycle for engagement partners performing financial statement audits. See ISQM 1 paragraph A153, SQMS 1 paragraph A165.

approach, including the nature, timing, and extent of planned audit procedures);

- Evaluating an engagement team's progress against certain defined milestones or metrics and taking appropriate action when such milestones or metrics are not achieved (e.g., if an engagement partner did not review an engagement team's planning memo before interim audit procedures were to start, adjusting the engagement team's schedule so that the document could be reviewed and comments addressed before starting interim work; if an engagement team's hours exceed a certain weekly threshold, taking action by identifying the issue and adding additional resources to the team); and
- Monitoring engagement team turnover during the engagement and taking appropriate action when issues arise (e.g., if more experienced or senior personnel on the engagement, such as the manager or senior manager, leaves the firm during the engagement and prior to the completion of procedures, taking actions to ensure the engagement team has the necessary resources to complete the engagement).

The proposed standard contemplated that firms that issue audit reports with respect to more than 100 issuers during the prior calendar year would be required to monitor in-process engagements. The proposal noted the Board's understanding that monitoring in-process engagements may be challenging for some firms based on their size and nature, so the proposed standard also included a "should consider" requirement to provide sufficient scalability for firms that issue audit reports with respect to 100 or fewer issuers. Under the proposed standard, firms that audit 100 or fewer issuers would be expected to reach a conclusion about whether to monitor in-process engagements in light of identified quality risks and quality responses.

Firms that commented on this requirement supported the concept of monitoring in-process engagements and the flexibility the standard provided for firms to design their in-process monitoring based on the nature and circumstances of the firm. Two firms stated that the purposes of in-process monitoring are clear and appropriate and that the proposed standard clearly distinguished between in-process engagement monitoring and engagement quality reviews under AS 1220. Two firms suggested that the 100-issuer threshold is not necessary, and that all firms should only be required to consider whether to monitor in-process engagements.

The Board believes that differentiating a firm's obligation based on the number of issuer clients is appropriate because, in its view, firms with larger, more complex audit practices generally are subject to quality risks for which in-process monitoring is an appropriate quality response. The Board based the requirement on the size of a firm's issuer audit practice rather than its broker-dealer audit practice, as it believes the number of a firm's issuer clients is more indicative of the firm's size and the complexity of its practice. And, as noted above, firms are familiar with the threshold of more than 100 issuer audit reports. The majority of firms with 100 or fewer issuers do not perform in-process engagement monitoring activities. Requiring these firms to perform such monitoring activities could significantly change current practice and is not justified by the circumstances of every firm. However, due to the benefits of this proactive engagement monitoring, the standard requires that firms that do not meet the 100-issuer threshold should consider monitoring in-process engagements. The Board believes that this approach strikes an appropriate balance between prescriptiveness and scalability, and adopted the requirement as proposed.

One individual commenter suggested that audit firms would find it cost prohibitive to build in "in process" controls that would be akin to doing an inspection of an audit in process, with the exception of certain circumstances, but the PCAOB did not receive any specific comments from firms expressing that concern. In addition, firms with over 100 issuer clients typically have the resources to implement such procedures, and based on PCAOB oversight activities, the majority of them already monitor in-process engagements to some extent.²⁹⁰

In situations where the firm participates in another firm's engagement but does not play a substantial role, paragraph .63c provides that the firm should consider performing monitoring activities on such work. Some commenters agreed with the requirement for firms to consider performing monitoring activities on their work on other firms' engagements. When deciding whether and when to do so, and what monitoring activities to perform, firms would take into account the factors identified in paragraph .64, such as the firm's monitoring and external inspection

history and the risks associated with the performance of the work. In addition, if a substantial portion of the firm's activities that are subject to the QC system relate to work performed on other firms' engagements at less than a substantial role, the firm would have to make that decision in light of the overall objectives of the QC system.²⁹¹

One commenter requested clarification as to whether the in-process monitoring activities the Board has observed would be sufficient to meet the requirement, or whether the Board expects such activities to be expanded or enhanced. The standard does not specify any particular monitoring activities, so the firm has discretion to select activities based on the nature and circumstances of the firm and its engagements and the scope and nature of its other monitoring activities. For example, when determining which engagements to select for in-process monitoring, a firm would leverage the factors presented in paragraph .64 of the standard to identify engagements where there is a greater risk of noncompliance with applicable professional or legal requirements. Similarly, these factors will also assist a firm in determining the riskier areas of such engagements upon which to perform in-process engagement monitoring activities.

i. Designing Engagement Monitoring Activities, Including Selecting Which Engagements To Monitor (QC 1000.64)

Similar to the proposal, the final standard requires a firm to take into account certain factors when determining the nature, timing, and extent of engagement monitoring activities, including which completed or in-process engagements to select for monitoring. These factors reflect aspects of a firm and its engagements that could create a greater risk of noncompliance with applicable professional and legal requirements. A firm will need to tailor its monitoring activities to address the particular circumstances of the firm and select engagements for monitoring based upon their specific risks.

The factors are:

- *Quality risks and the reason for their assessments, and quality responses.* For example, the complexity of or changes to applicable professional and legal requirements and the firm's policies and procedures may present a quality risk that the firm may not timely communicate the required use of a practice aid for planning audit procedures when certain fraud risk factors are present. In response to this risk, the firm would design its

²⁹⁰ In 2023, 11 of the 14 annually inspected firms performed some in-process engagement monitoring activities.

²⁹¹ See QC 1000.05a.(2).

engagement monitoring activities to verify the engagement team's use of the practice aid. The earlier these monitoring activities are performed, the more proactive the firm could be in planning audit procedures that address audit issues as they arise. Regarding the proposed factor in paragraph .64b related to the "design of the quality responses," the final standard has removed the word "design" from the factor and made other edits to clarify that the firm should also take into account the scope and operation of quality responses, for example related to information about how those quality responses operated in previous years.

- *The nature, timing, extent, and results of previous monitoring activities.* This includes insights learned from previous engagements and QC system-level monitoring activities that are applied when determining engagement monitoring activities to perform. For example, in selecting engagements for monitoring, the firm would take into account deficiencies identified in previous engagements for the same client and other engagements where a similar deficiency may exist. As another example, engagement deficiencies related to inventory obsolescence testing identified by a firm through prior year engagement monitoring activities may prompt a firm to monitor the testing of inventory obsolescence on more engagements in the current year. One commenter recommended a clarifying revision to paragraph .64c to change the reference to "inspections of in-process engagements" to "monitoring of in-process engagements." The commenter explained that the characterization of in-process engagement monitoring as an "inspection" is not consistent with how in-process engagement monitoring was described in the proposal, as the in-process monitoring activities observed by the PCAOB do not include inspections of in-process engagements. The Board agreed and included this revision in the final standard.

- *Information obtained from oversight activities by regulators, other external inspections or reviews, and, if applicable, monitoring activities performed by a network.* Information obtained from network monitoring activities or external reviews provides a firm direction as to, for example, the type of procedures to perform or when to perform them. The results of network monitoring activities or information obtained from external reviews could also identify issues that may exist on other similar engagements of the firm, prompting a decision to monitor some or all of these other engagements. For example, if an engagement was recently

inspected through network monitoring activities or an external review, a firm may determine that selecting the same engagement for internal inspection would be unnecessary.

The proposal included a note that a firm cannot rely solely on network monitoring activities or external inspections by regulators of individual engagements without performing its own inspections of completed engagements. One commenter, a firm, agreed with the proposed requirements for firms to perform their own monitoring activities rather than solely relying on the monitoring activities performed by the network. Another firm disagreed and recommended that the standard permit networks to perform monitoring activities on behalf of a member firm, including in certain circumstances as the sole source of a firm's QC engagement monitoring. This commenter stated that monitoring of completed and in-process engagements by the network may provide member firms in the network with more objective and experienced monitoring resources, and that smaller member firms may not have the resources to perform objective monitoring on completed and/or in-process engagements without leveraging the network. Similar to what is described below as it relates to a firm's QC system and the extent of monitoring activities performed by a network, regardless of whether a network performs engagement monitoring activities on a firm's engagements, the firm is ultimately responsible for its QC system and for evaluating any information it obtains from the network about any engagement monitoring activities the network performs. The firm would take into account the nature and extent of activities performed by a network in designing and implementing its own activities but all firms are required to perform some level of engagement monitoring. The final standard includes a clarifying revision to this note that replaces "inspections of completed engagements" with "engagement monitoring activities."

- *Characteristics of a particular engagement.* Factors such as the industry, the type of engagement (e.g., issuer audit, broker-dealer audit, attestation), the location(s) or jurisdiction(s) in which the client is located or the work is to be performed, whether it is a new engagement for the firm, and the experience and competence of the engagement team could affect conduct and outcomes of the engagement. For example, if the engagement team members are all new to the engagement, their lack of

historical knowledge may present an additional risk for that engagement and provide a basis for its selection for monitoring.

- *Characteristics of particular engagement partners.* Factors such as the experience and competence of engagement partners, the results of internal and external inspections of their work, and the firm's cycle for inspecting their engagements could affect the quality risks associated with an engagement, whether positively or negatively. For example, an engagement partner's lack of experience in an industry the company under audit recently entered may create additional risks to complying with applicable professional and legal requirements. Therefore, performing engagement monitoring activities on such engagements may be appropriate.

- *Other information relevant to the quality risks.* The standard includes a non-exhaustive list of examples. For clarity, this factor was rephrased in terms of "quality risks" rather than "risks of noncompliance with applicable professional and legal requirements." The standard also includes a footnote referencing footnote 26, which explains that the firm is deemed "aware" of information when any partner, shareholder, member, or other principal of the firm first becomes aware of such information.

The requirement is both principles-based and risk-centered, rather than prescriptive. It provides for scalability by including factors for firms to take into account when determining the nature, timing, and extent of engagement monitoring activities. In addition to the factors included in the standard, a firm may identify other factors that are also relevant based on the nature and circumstances of the firm and its engagements.

d. QC System-Level Monitoring Activities (QC 1000.65)

Similar to the proposal, the final standard requires a firm to take into account certain factors when determining the nature, timing, and extent of QC system-level monitoring activities.

Due to their nature, some of the factors are consistent with the factors a firm is required to take into account when determining the nature, timing, and extent of engagement monitoring activities, such as the quality responses, including their timing, frequency, scope and operation. Regarding the proposed factor in paragraph .65b related to the "design of the quality responses," conforming to the change made in paragraph .64b, the word "design" was

removed from the factor and made other edits to clarify that the firm should also take into account the scope and operation of quality responses, for example related to information about how those quality responses operated in previous years. The specific features of a firm's quality responses are also relevant for a firm to consider when designing QC system-level monitoring activities. For example, a firm's quality responses related to acceptance and continuance of engagements might include a policy that firm personnel complete a checklist and assemble information evaluated by the engagement partner before making a recommendation to firm leadership on whether to continue with an engagement for the upcoming year. Based on this quality response, a firm might design QC system-level monitoring activities that include a review of the checklist and documentation for a selection of engagements.

Some other factors the standard requires firms to take into account when determining the nature, timing, and extent of QC system-level monitoring activities include:

- *The design of a firm's risk assessment and monitoring and remediation processes.* The design of these processes is relevant when designing monitoring activities to evaluate if such processes are implemented and operating effectively. For example, a firm may monitor the cyclical basis determined by the firm for inspecting engagement partners' completed engagements. A firm's monitoring activities in this area could include whether the firm is complying with the established period for selecting completed engagements as well as evaluating whether changes to the period may be necessary based on the results of other monitoring activities. The firm could also develop metrics for its QC system and use them in its monitoring and remediation process.

- *Changes in the QC system.* As a firm's QC system is continuously evolving in response to changes in risks, the firm would have to consider whether and how such changes necessitate changes to the nature, timing, and extent of QC-system level monitoring activities. For example, changes to a quality response would be an indication that changes to the activities that monitor the design, implementation, and operation of such response may be necessary. It should be noted that, even in the absence of changes in the QC system, for example in cases where the firm determines that there have been no changes related to a

particular quality response, the firm would still need to consider whether previous monitoring activities related to that quality response continue to provide the firm with a reasonable basis to evaluate the QC system, including the appropriateness of the firm's monitoring activities for the current period.

- *When applicable, services provided by other participants in the firm's QC system.* A firm may use other participants in its QC system (for example, other participants may assist with engagement quality reviews). The firm would take that into account when deciding what QC system-level monitoring activities to undertake (for example, assessing other participants' compliance with PCAOB standards regarding engagement quality reviews).²⁹²

A firm's monitoring activities are likely to vary over time as a firm takes into account the factors included in the standard (see paragraphs .64–.65). Since a firm's QC system is a continuous and iterative process, such factors will generally lead a firm to perform different monitoring activities or employ different monitoring approaches over time.

Several commenters, including investor-related groups, suggested that the standard should require that the monitoring and remediation process, or more generally QC 1000, provide for use of quantitative metrics. QC 1000 does not require firms to use quantifiable metrics in their monitoring activities or suggest the use of any particular metrics. The Board has recently proposed a new set of firm reporting requirements that includes both firm-level and engagement-level metrics, and the comments regarding metrics received in response to the QC 1000 proposal are addressed in that proposing release.²⁹³

Other than removing the word “performance” from the phrase “performance metrics,” to align with the terminology used in the PCAOB's proposed metrics requirements, the Board adopted as proposed paragraph .65c, which requires the firm to take into account any metrics that the firm may use in its QC system when determining the nature, timing, and extent of QC system-level monitoring activities. This could include, but is not required to include, any metrics firms would be required to report if the metrics proposal is ultimately adopted by the Board and approved by the SEC, as well as any additional metrics a firm may develop. Depending on their

circumstances, firms may find that developing metrics to monitor engagements and the QC system would enhance their ability to identify deficiencies, measure whether quality objectives have been met, and evaluate the effectiveness of remediation activities.

e. Monitoring Activities Performed by a Network (QC 1000.66)

The Board adopted substantially as proposed the requirements that apply when networks perform monitoring activities relating to a firm's QC system or engagements. Networks employ a variety of different approaches to monitoring firm QC systems. Some networks perform monitoring activities either directly on the firm's QC system, such as monitoring a firm's compliance with QC policies and procedures established by the network and adopted by the firm, or on tools or other resources developed or purchased by the network and used by the firm, such as an independence tracking system. Other networks perform no monitoring activities.

The nature and extent of a network's monitoring activities will inform a firm's approach to monitoring. To illustrate, if a firm used a network independence tracking system to identify matters that may bear on the independence of firm personnel, and if the network monitored the design and operation of the tracking system and provided the firm with relevant information about those activities, the firm is required to evaluate the monitoring activities performed by the network on the tracking system. In performing its evaluation, the firm needs to understand the scope of the network monitoring activities, such as whether the firm's personnel were selected for monitoring procedures, and if so, whether the population selected was sufficient to provide a reasonable basis for detecting engagement and QC deficiencies. To the extent provided, the firm is also required to evaluate the results of the testing performed by the network, and if deficiencies were identified, the remedial actions, if any, taken or proposed to be taken by the network. Under this example, the firm would also determine its responsibilities in assisting the network with any monitoring or remediation activities related to the tracking system.

Regardless of any QC monitoring activities that a network may perform on behalf of the firm, the firm is ultimately responsible for its QC system. Therefore, under the standard, the firm is responsible for evaluating any information it obtains from the network

²⁹² See generally, e.g., AS 1220.

²⁹³ See PCAOB Rel. No. 2024–002 at 12–13.

about any QC monitoring activities the network performs. Some commenters, all of which were firms, supported the proposed requirements related to monitoring activities performed by a network.

A firm is required to adjust its monitoring activities as necessary, based on the scope of the network's monitoring activities and the information the firm receives (or does not receive) from the network about those activities. One commenter expressed concern that the proposal allows the firm to request certain categories of information from a network but does not require that the information actually be received. In situations where a firm does not receive information requested from the network about the monitoring activities the network performed, the firm would not be in a position to take such activities into account in planning its own activities. To illustrate, a network may provide information to a firm regarding the results of member firms' internal engagement monitoring activities, which the firm uses to evaluate the competence of other network firm personnel and their ability to participate in the firm's engagements. If, due to a change in a particular network firm's local privacy laws, the network is unable to provide such information regarding that member firm, the firm will need to evaluate that member firm's competence and ability using a different approach.²⁹⁴ To illustrate another case, if a firm requests but does not receive any information from the network regarding QC monitoring activities related to independence that the network performed on behalf of the firm, and the firm does not perform any monitoring activities related to its QC system in that area, the firm would have no basis for concluding that the quality objectives related to independence were achieved.

f. Determining Whether Engagement Deficiencies Exist (QC 1000.67)

The requirements for determining whether engagement deficiencies exist did not draw comment and were adopted with one modification, described below.

As defined by the standard, an engagement deficiency is an instance of noncompliance with applicable professional or legal requirements by the firm, firm personnel, or other participants with respect to an

engagement of the firm, or by the firm or firm personnel with respect to an engagement of another firm.

Engagement deficiencies include:

- Instances of noncompliance in which a firm did not adequately support its opinion—because the firm did not perform sufficient procedures, obtain sufficient appropriate evidence, or reach appropriate conclusions with respect to relevant financial statement assertions;
- Instances in which the firm did not fulfill the objective of its role in the engagement, such as not performing attestation services in accordance with AT No. 2; and
- Other instances of noncompliance with applicable professional and legal requirements with respect to a firm's engagement, which may include, for example, not satisfying applicable independence requirements,²⁹⁵ not making required communications to the audit committee,²⁹⁶ or not filing Form AP.²⁹⁷

The standard requires a firm to evaluate a variety of information in making its determination about whether an engagement deficiency exists, including internally developed information from monitoring activities, information from external parties like regulators and peer reviewers, and other relevant information of which the firm becomes aware. Beyond the sources specified in the standard, a firm is not expected to seek out other sources of information that may indicate an engagement deficiency exists. However, if the firm becomes aware of such information, the firm is expected to evaluate it. For purposes of the standard, the firm is deemed "aware" of information when any partner, shareholder, member, or other principal of the firm first becomes aware of such information. The Board made a change to the proposed note in paragraph .67e item (4) to clarify that complaints the firm becomes aware of, that may indicate the existence of an engagement deficiency, could be related to either a company or the firm. The language was also broadened to clarify that complaints are not limited to those submitted through a formal whistleblower program.

The standard does not specify how a firm would evaluate information to determine whether an engagement deficiency exists. Rather, it provides firms the ability to develop an approach

for such evaluation. A determination that an engagement deficiency exists due to the firm not complying with a PCAOB reporting requirement may be relatively simple to make. For example, evaluating whether the firm filed a Form AP in accordance with PCAOB Rule 3211 would not require a significant amount of effort. However, evaluating information indicating the firm did not perform the necessary audit procedures for an issuer's revenue transactions to determine whether an engagement deficiency exists could be more complex, and therefore require a more in-depth analysis.

A firm's determination that an engagement deficiency exists may pertain to an in-process engagement, a completed engagement, or work performed on other firms' engagements.

If a firm obtains information about a potential deficiency in an in-process engagement, whether from monitoring activities or other sources, the firm is expected to evaluate the information to determine whether an engagement deficiency exists before the engagement report is issued. In that regard, it should be noted that identifying a problem while an engagement is in process may enable the firm to rectify the problem before an engagement deficiency could arise. Many professional and legal requirements that apply to performing an engagement impose ongoing responsibilities that are not completed until the engagement itself is completed. In relation to such ongoing responsibilities, if a problem is identified in an in-process engagement but resolved before the engagement is completed, no engagement deficiency would arise. For example, if an engagement team initially failed to obtain sufficient appropriate audit evidence in its testing of revenue because it failed to perform a necessary procedure, the engagement team could still perform the procedure at a later time during the engagement; as long as sufficient appropriate audit evidence was obtained prior to the issuance of the report, there would be no engagement deficiency. QC 1000 does not have specific provisions to address remediation of this type of problem because the auditor's responsibility is already addressed by applicable professional and legal requirements. However, even in instances where an engagement deficiency does not arise because a problem was identified and corrected prior to issuance of an engagement report, a firm would still need to consider whether the existence of the problem constitutes a QC observation—an observation about the design, implementation, or operation of

²⁹⁴ Irrespective of how the evaluation is performed, the engagement partner's responsibility for the engagement and its performance would not change. See AS 1201.03.

²⁹⁵ See generally, e.g., 17 CFR 210.2–01; PCAOB rules under Section 3. Auditing and Related Professional Practice Standards, Part 5—Ethics and Independence.

²⁹⁶ See generally AS 1301.

²⁹⁷ See PCAOB Rule 3211, *Auditor Reporting of Certain Audit Participants*.

the firm's QC system that may indicate one or more QC deficiencies exist—and, ultimately, a QC deficiency.

By contrast, some applicable professional and legal requirements (such as those relating to preliminary engagement activities, including engagement acceptance procedures, and certain required communications to the audit committee) are required to be complied with prior to or at the beginning of the engagement. With respect to those requirements, an engagement deficiency would arise if the required time for performance had passed and the required activities were not performed appropriately, even if the engagement was still in process.

The standard requires determinations to be made on a timely basis. For completed engagements, the timeliness of the determination depends on the nature of the information subject to evaluation. For example, if the information suggested other engagements may present a similar issue, then it would be expected that determination would be made sooner so that the risk of engagement deficiencies on other engagements—whether in-process or completed—is mitigated.

The final standard was revised to clarify that the evaluation and determination of whether engagement deficiencies exist must both be done on a timely basis.

g. Responding to Engagement Deficiencies (QC 1000.68)

Under the final standard, when a firm determines an engagement deficiency exists, the firm is required to take action to address the deficiency. The action taken would depend on whether the engagement deficiency related to an in-process engagement, a completed engagement, or work performed by the firm on other firms' engagements. In some instances, a firm may find it beneficial to perform a root cause analysis to determine what action to take.

i. Engagement Deficiency Related to an In-Process Engagement

For an engagement deficiency related to an in-process engagement, the proposed standard provided that the firm take action to address the deficiency in accordance with applicable professional and legal requirements. The nature of the engagement deficiency would determine what a firm would need to do to address it and the timing of the required action. For engagement deficiencies that could affect the auditor's report, under the proposed standard, remedial action would be required before the

engagement report is issued, such that the engagement report issued is appropriate in the circumstances. In other instances, action would still be required to address the deficiency, but the firm would have more flexibility regarding when such actions are performed; action could be performed either before the report is issued or afterwards (if afterwards, the provisions of paragraph .68b would apply). The Board adopted substantially as proposed the requirement for responding to an engagement deficiency on an in-process engagement.

ii. Engagement Deficiency Related to a Completed Engagement

For an engagement deficiency related to a completed engagement, the proposed standard included a requirement for firms to take action to address the engagement deficiency in accordance with applicable professional and legal requirements (discussed in more detail below in connection with paragraph .70). However, under the proposed requirement, no action would have been required if it was probable that the engagement report was not being relied upon.²⁹⁸

The proposed standard included a note that stated the firm must treat an auditor's report as being relied upon if the auditor's report is included in the most recent SEC filing on a form that requires its inclusion. Because this note also appeared in the proposed amendments to AS 2901 in paragraph .01, refer to the detailed discussion below for commenter feedback and the Board's responses. The note to paragraph .68b. was revised to provide that, in the absence of circumstances indicating that reliance is impossible or unreasonable (e.g., cessation of a trading market for issuer securities), inclusion of an engagement report in the most recent filing on an SEC form that requires inclusion of such an engagement report generally evidences that the report is being relied upon. The Board believes this is responsive to commenter concerns and allows for sufficient flexibility for such circumstances. The note was also revised to clarify that an engagement report can be included in an SEC filing either directly or through incorporation by reference.

²⁹⁸ The use of "probable" in the note to paragraph .68 is consistent with how the term is used in FASB ASC, Contingencies Topic, paragraph 450–20–25–1, which provides that an event is "probable" when it is likely to occur.

iii. Engagement Deficiency Related to Work Performed on Other Firms' Engagements

For an engagement deficiency related to work performed on other firms' engagements, the standard requires a firm to communicate to the other firm the engagement deficiency. The communication needs to be sufficient to enable the other firm to develop a response commensurate with the extent of noncompliance. These engagement deficiencies, while there may or may not be additional remedial actions for the firm to take related to the particular work performed, should be included in the population of QC observations to be evaluated to determine whether QC deficiencies exist. The Board did not receive comment on this aspect of the proposal and adopted it as proposed.

iv. Evaluating Whether Similar Engagement Deficiencies Exist

The proposed standard also required a firm to evaluate whether similar engagement deficiencies exist in other in-process engagements, completed engagements (unless it is probable that the engagement report is not being relied upon), and work performed on other firms' engagements, and if so, to take actions as required by paragraphs .68a.–c. for in-process engagements, completed engagements, and any other work performed by the firm on other firms' engagements at less than a substantial role. Understanding the nature of the engagement deficiency will assist the firm in determining the extent of the necessary evaluation. To illustrate, if the engagement deficiency was caused by an error in the firm's methodology for auditing a company's loan valuation allowance, then the firm would evaluate whether similar engagement deficiencies exist on engagements that were also using that methodology. As another example, if engagement team members did not comply with PCAOB standards when auditing accounts receivable because they failed to perform certain procedures in the firm's audit program, the firm would evaluate whether the person(s) who were responsible for performing the procedures and the person(s) supervising the work participated in any other audit engagement's accounts receivable testing, and if so, whether similar engagement deficiencies exist.

One commenter requested that the Board provide additional examples of engagement deficiencies, as the concept of applicability to other in-process engagements could be subject to different interpretations. The Board will

consider whether application guidance in this area would be appropriate.

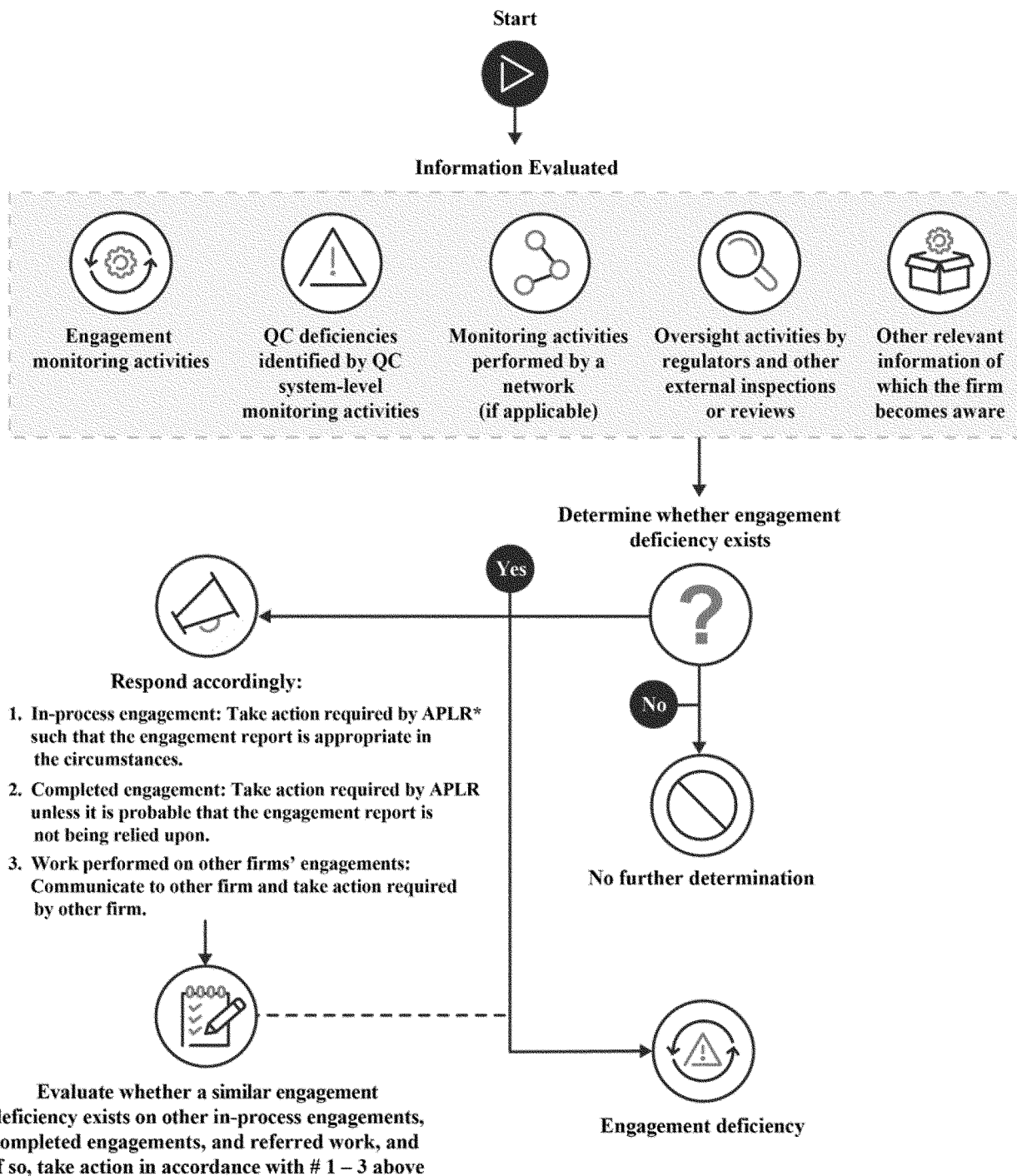
Another commenter stated that the expectation of what “evaluate,” as used in this context, may require is not clear and suggested that the evaluation be limited to certain engagements based on

a risk-based assessment, taking into consideration the root cause of the identified engagement deficiency. As noted above, understanding the nature of the engagement deficiency would assist the firm in determining the extent

of the actions to take in order to evaluate whether similar engagement deficiencies exist on other engagements.

The Board adopted this aspect of the standard as proposed.

BILLING CODE 8011-01-P



*APLR = Applicable professional and legal requirements

BILLING CODE 8011-01-C

v. Addressing Engagement Deficiencies (QC 1000.69–70)

Paragraph .69 of the standard requires firms to respond to engagement deficiencies by taking into account the nature and severity of the engagement deficiency. In other words, the response should be targeted based on the nature of the problem and proportionate to the severity of the problem.

Understanding the nature and severity of an engagement deficiency could assist firms in:

- Developing an appropriate response to the engagement deficiency;
- Determining whether an engagement deficiency could relate to other engagements; and
- Assessing whether the engagement deficiency, which represents a QC observation, is also a QC deficiency.

The actions taken by the firm to respond to engagement deficiencies may include preventive or corrective actions (or a combination of these actions):

- *Corrective actions* are actions taken to rectify an identified deficiency in a current or completed engagement (for example, performing a procedure that had been omitted, designing and performing additional or alternative procedures if audit evidence is insufficient, or filing a required report).
- *Preventive actions* are actions taken to prevent the occurrence of a deficiency in future engagements (for example, training, developing audit tools, or enhancing audit methodology).

The proposed note to this requirement also appeared in the proposed amendments to AS 2901.04 and a detailed discussion of commenter feedback and the Board's views appears below. As adopted, the note in paragraph .69 includes clarifying changes. The requirement was otherwise adopted as proposed.

The proposed requirement in paragraph .70 did not draw comment and the Board adopted it as proposed. Firms should comply, as applicable, with other standards related to engagement deficiencies on completed engagements.

- AS 2901 addresses auditor responsibilities with respect to engagement deficiencies on completed audit engagements. AS 2201.99 directs the auditor to comply with AS 2901 as it relates to audits of internal control over financial reporting.

- AS 2905 deals with auditor responsibilities when, subsequent to the date of a report on audited financial statements, the auditor becomes aware of facts that might have affected the report had he or she then been aware of

such facts before issuing the report. AS 2201.98 is a similar provision relating to auditor's reports on internal control over financial reporting.

- AT No. 1 and AT No. 2 incorporate responsibilities similar to those required under AS 2901 for attestation engagements relating to certain broker-dealer reports.

The amendments to AS 2901 are discussed below.

h. Determining Whether QC Observations Exist (QC 1000.71)

The proposed standard would have required firms to determine the existence of "QC findings," defined as "[a] finding about the design, implementation, or operation of the firm's QC system that may indicate one or more QC deficiencies exist. Engagement deficiencies are QC findings."

Commenter feedback on this defined term was in most instances directly related to the last sentence in the defined term, urging that engagement deficiencies should not automatically be considered QC findings. The Board was concerned that commenters may have misinterpreted "QC findings" as akin to "QC deficiencies," whereas the intention is only to designate matters that have to be evaluated as potential QC deficiencies. To alleviate the potential confusion, the defined term was changed to "QC observation" and the definition reworded. The definition of a QC observation in the final standard is "(1) An engagement deficiency; or (2) Any other observation about the design, implementation, or operation of the firm's QC system that may indicate one or more QC deficiencies exist."²⁹⁹

Under the definition, any information that may indicate a problem with the design, implementation, or operation of the firm's QC system would be a QC observation. Because a QC system provides reasonable assurance that engagements are conducted in accordance with applicable professional and legal requirements, all engagement deficiencies would be QC observations. Examples of other QC observations include an error in the design or operation of a technology tool or methodology, or information suggesting that a firm may not have achieved a quality objective.

The determination of QC observations involves collecting observations and related evidence that may indicate a QC deficiency exists, including information from monitoring activities, information from external parties like regulators and

peer reviewers, and other relevant information of which the firm becomes aware.

Under the standard, the results of all monitoring activities performed by the firm, and if applicable, those performed by a network relating to the firm's QC system or its engagements, are required to be analyzed by the firm to determine if there are QC observations. It is possible that a firm's engagement monitoring activities could identify not only engagement deficiencies, but also QC observations that are not engagement deficiencies. For example, if, as part of the firm's quality response related to technological resources, the firm's technology leader must review and approve all software audit tools used on engagements, and if a firm's engagement monitoring activities reveal that an engagement team did not receive the appropriate authorization to use a specific tool, that observation would be a QC observation, regardless of whether the use of the tool also gave rise to an engagement deficiency.

Oversight activities by regulators and external inspections or reviews include activities of the PCAOB and other regulators. As a firm typically has one QC system for its entire audit practice, the results of the inspections, reviews, and other oversight activities performed by these external parties would likely be relevant to a firm's determination of whether QC observations exist.

Other relevant information of which the firm becomes aware would comprise information obtained from within and outside the firm. A firm would not be expected to seek out such other sources of information; however, if other relevant information came to the firm's attention, a firm is expected to determine whether it is a QC observation. For example, the firm may become aware of an issue with a formula in a practice aid used to assist engagement teams in auditing stock-based compensation if a member of an engagement team communicates that issue to firm personnel supporting the firm's QC system.

The final standard has been revised to clarify that the evaluation and determination must both be done on a timely basis.

i. Determining Whether QC Deficiencies Exist (QC 1000.72)

The standard requires firms to determine whether QC deficiencies exist, and (except for the change in terminology to "QC observation") was adopted as proposed.

²⁹⁹ QC deficiencies are defined and discussed in the next subsection. See below.

i. Definition of QC Deficiency

In response to commenter input, the Board made changes to the definition of the term “QC deficiency.” As proposed, the definition provided in part that a QC deficiency was a QC finding that results in “a reduced likelihood of the firm achieving the reasonable assurance objective or one or more quality objectives,” and included a note providing examples of circumstances where that likelihood could be reduced. Two commenters questioned the operability of that aspect of the proposed definition of QC deficiency, in particular its linkage to the definition of an internal control deficiency under COSO in its integrated framework through the phrase “reduced likelihood.” Two commenters suggested that the definition of QC deficiency should incorporate the concept of “a significantly reduced likelihood.” Another commenter requested guidance relative to the application of the “reduced likelihood” model. Other commenters suggested that the definition should be more closely aligned with that of other standard setters, for example ISQM 1, by incorporating the concept of an “acceptably low level.”

Taking into account commenter feedback, the standard defines a QC deficiency as a QC observation that, based on the evaluation under paragraph .72, individually, or in combination with one or more other QC observations, evidences:

- That the likelihood of the firm not achieving the reasonable assurance objective or one or more quality objectives has not been reduced to an acceptably low level;

Note: The likelihood of not achieving the reasonable assurance objective or one or more quality objectives would be above an acceptably low level if, for example, a quality objective is not established, a quality risk is not properly identified or assessed, or a quality response is not properly designed or implemented or is not operating effectively.

- Noncompliance with requirements of this standard, other than those under “Documentation”; or

- Noncompliance with requirements of this standard under “Documentation” that adversely affects the firm’s ability to comply with any of the other requirements of this standard.

The first subparagraph of the definition of QC deficiency incorporates an existing concept of “acceptably low level” that is currently used in PCAOB auditing standards³⁰⁰ so this concept

should be familiar to firms. In addition, it aligns more closely with similar definitions of other standard setters, for example the definition of “deficiency” in ISQM 1. The Board made conforming changes to the note that follows subparagraph (1) of the definition.

Similar to the proposal, the definition of QC deficiency in the final standard also includes noncompliance with the requirements of the proposed standard other than documentation requirements, such as the requirements related to roles and responsibilities, the firm’s risk assessment process, the monitoring and remediation process, and the evaluation of the QC system. Two commenters expressed concern with this requirement, stating that there may be instances where the firm may not comply with a requirement in the standard but the quality objectives and specified quality responses were met, and a firm should be able to apply judgment to determine whether a QC deficiency exists under those circumstances. The Board continues to believe that compliance with the requirements of QC 1000 is a baseline element of any firm’s QC system, such that failure to comply is always a QC deficiency, and adopted this aspect of the QC definition as proposed.

The definition also includes noncompliance with the documentation requirements of QC 1000, to the extent that such noncompliance adversely affects the firm’s ability to comply with any of the other requirements of the proposed standard, while excluding other documentation issues. For example, a firm’s failure to document some details of its monitoring activities, in a context where the firm otherwise sufficiently documents the evaluation of the results from its monitoring activities, would not meet the definition of a QC deficiency. The Board received no comment on this aspect of the definition of QC deficiency and adopted it as proposed.

Under the final standard, the determination of whether something identified as a QC observation meets the definition of a QC deficiency would be based on the nature, severity, and pervasiveness of the underlying matter; the likelihood that it could affect other component(s) of the QC system or other engagements; and the severity of such an effect if it were to occur. In the case of engagement deficiencies, this evaluation would take account of the basis for the firm’s determination of the actions required under paragraph .68 of QC 1000, including any root cause analysis performed. These considerations are discussed, in turn, in the following subsections.

The final standard has been revised to clarify that the evaluation and determination must both be done on a timely basis.

ii. Nature, Severity, and Pervasiveness of the Matter That Gave Rise to the QC Observation

The nature, severity, and pervasiveness of the matter that gave rise to the QC observation should be taken into account when determining whether a QC deficiency exists. For a QC observation that is also an engagement deficiency, the results of the firm’s evaluation of whether a similar engagement deficiency exists on other in-process and completed engagements would provide useful information to the firm when determining whether a QC deficiency exists.

The standard explains that the nature, severity, and pervasiveness of the matter that gave rise to the QC observation includes:

- *The component(s) of the QC system, quality objective(s), or quality risk(s) to which the QC observation relates.*

Depending on the quality risks that a firm identifies, some components may play a greater role in its QC system than others. For example, for a small firm that audits one issuer and has no intention to expand its issuer audit practice, the engagement performance component would have a greater role than acceptance and continuance of engagements because the quality risks associated with the new engagement would be mitigated by the firm’s policy of not taking on new issuer audit engagements. Based on the firm’s risk assessment, certain quality risks may pose a greater threat to the firm’s QC system than others. In addition, some QC observations may relate to a single component of the QC system or a single quality objective, while others may relate to multiple components of the QC system or multiple quality objectives. For example, an engagement deficiency may relate to the resource component (e.g., competence and training of firm personnel, firm methodology), the information and communication component (e.g., failure to communicate changes to the methodology), or the engagement performance component (e.g., failure to consult when required), or all three of those components.

- *Whether the QC observation is in the design, implementation, or operation of the QC system.* For example, a matter that gave rise to a QC observation in the design of a process has a greater likelihood of being pervasive to a firm’s practice than a

³⁰⁰ See, e.g., AS 2315, *Audit Sampling*.

process that did not operate as designed on one occasion.

- *The frequency with which the QC observation occurred.* Frequency relates to the number of times the matter that gave rise to the QC observation occurred—for example, on engagements within a particular industry sector or practice group, a particular office, or firmwide. It might also relate to the number of times the observation was identified, the number of firm personnel involved, or the number of quality objectives affected. When related to the execution of a firm's quality response, it would also include relative frequency of QC observations compared to the number of times the procedure was executed properly.

The duration of time that the QC observation existed. Duration addresses how long the matter that gave rise to the QC observation existed. In order to understand duration, a firm would need to understand whether there were other instances prior to those initially identified by the firm as QC observations.

iii. Likelihood That the Matter That Gave Rise to the QC Observation Could Affect Other Component(s) of the QC System or Other Engagements, and the Severity of Such an Effect

Whether a QC observation is a QC deficiency would also depend on the likelihood that the matter that gave rise to the QC observation could affect other QC system components or other engagements.

Other engagements include in-process engagements, completed engagements, engagements to be performed in the future, as well as work performed on other firms' engagements. A firm may design and implement mitigating actions to address an engagement deficiency when such a deficiency comes to the firm's attention. When considering the likelihood that future engagements could be affected (for purposes of determining whether a QC deficiency exists), a firm would not take into account any mitigating actions, even if they have been implemented. This is because the determination of whether a QC deficiency exists must be made based on the nature, severity, and pervasiveness of the matter that gave rise to the QC observation, viewed on its

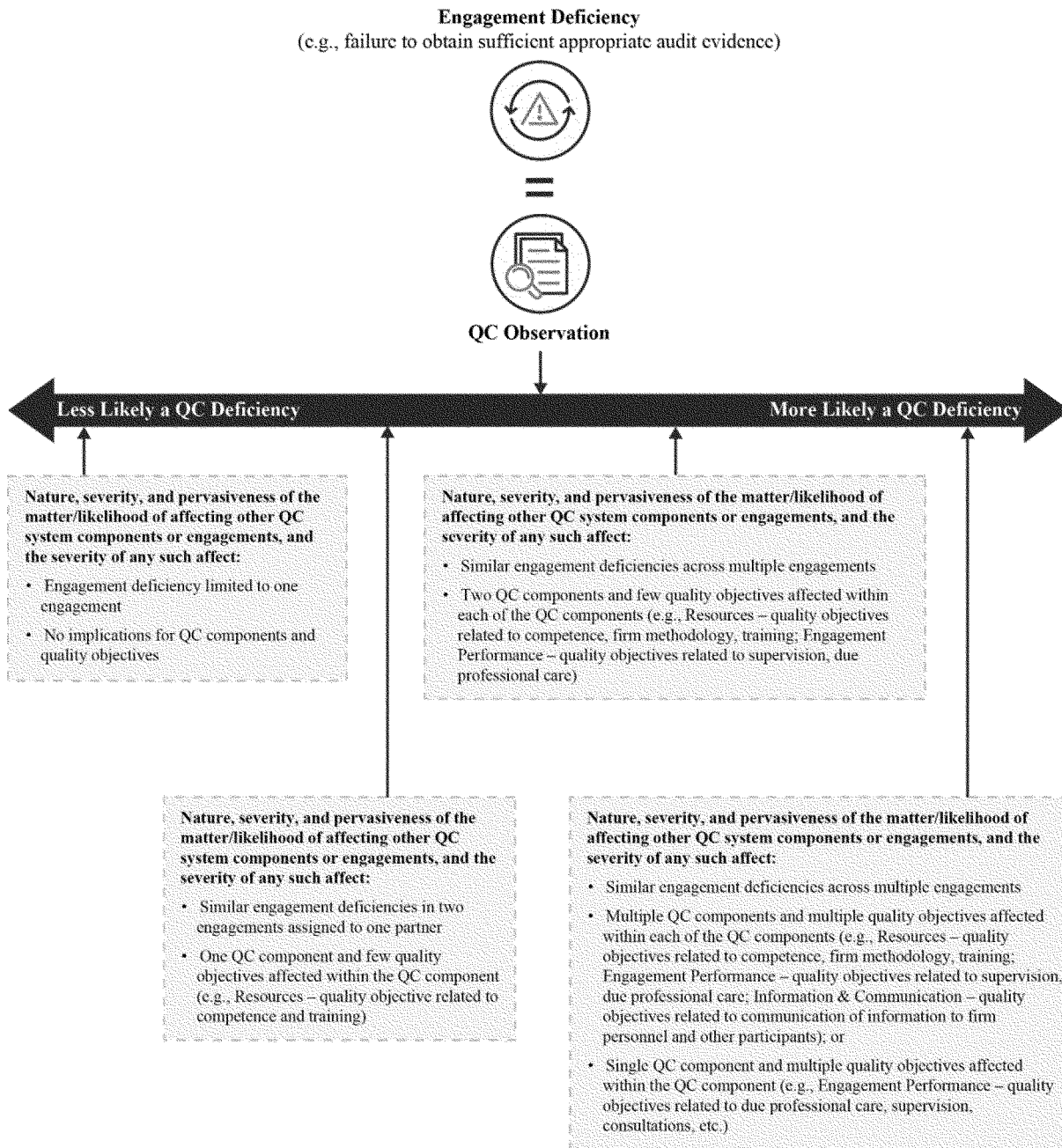
own. That shows the extent to which the QC system failed in allowing the underlying matter to occur. Whether the firm was subsequently able to partially or fully remediate the QC deficiency does not eliminate the fact that the failure occurred.

In addition to the likelihood of a matter's recurrence, the standard also requires a firm to evaluate the matter's severity if it were to affect other component(s) or engagements.

One commenter suggested that the standard address the concept of compensating responses as a factor when considering QC findings in proposed paragraph .72. In considering whether a QC observation is a QC deficiency (on the basis that the likelihood of the firm not achieving the reasonable assurance objective or one or more quality objectives has not been reduced to an acceptably low level) the firm could consider compensating responses that address the same quality risk. Additional discussion in response to this commenter's feedback appears below in the context of discussion of remedial actions.

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Example of Considerations Relevant to Determining QC Deficiency



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j. Responding to QC Deficiencies

i. Root Cause Analysis (QC 1000.73–.74)

The requirement to perform root cause analysis on all identified QC deficiencies did not draw comment and was adopted as proposed.

Root cause analysis is a widely used concept in QC frameworks.³⁰¹

³⁰¹ See *Spotlight: Root Cause Analysis—An Effective Practice to Drive Audit Quality* (April 2024) available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/documents/root-cause-spotlight.pdf?sfvrsn=55f82206_2.

Identifying and understanding the underlying causes of a problem supports developing solutions that address those causes, rather than just the symptoms. Proper determination of the causal factors that led to QC deficiencies is essential to developing effective remedial actions. For example, a policy or procedure could be inappropriately designed or implemented or a person may not have complied with a policy or executed a procedure as it was intended. As another example, an audit tool may not have operated as intended. Root cause analysis looks for different

types of causes through investigating the patterns of negative effects, finding hidden flaws in the QC system, and discovering specific actions that contributed to the problem. Improvements in audit quality have generally been observed through PCAOB oversight activities where a firm has established an effective root cause analysis program.³⁰² Many different types of causes may contribute to a problem.

³⁰² See 2018 Inspection Observations Preview.

A firm might find it helpful when performing root cause analysis to leverage information obtained from its evaluation of whether a QC deficiency exists. That is, information about the nature, severity, or pervasiveness of the matter that gave rise to the QC observation and the likelihood that the matter that gave rise to the QC observation could affect other components of the QC system or other engagements may provide evidence of what caused the problem to occur.

Root cause analysis procedures could take different forms depending on the circumstances, which allows for scalability. Some key elements that the PCAOB has observed that may lead to more robust and comprehensive root cause analysis include:³⁰³

- Monitoring audit deficiencies identified and performing root cause analysis on a continual basis. This allows firms to obtain information that allows them to react more timely and implement remedial actions to reduce recurring deficiencies in other audits.³⁰⁴
- Process mapping at the engagement level and the firm level of the underlying work flows of how a firm conducts its practice. A well-defined process makes it easier to analyze negative events to determine what went wrong.
- Consideration of both positive and negative quality events (*i.e.*, actions, behaviors, or conditions that resulted in positive or negative outcomes) to identify whether such actions, behaviors, or conditions were present on engagements where QC deficiencies were identified.
- Measuring, in real time, the effectiveness of remedial actions and audit quality improvement plans or initiatives to identify whether remedial efforts are effective.

The standard does not require firms to perform root cause analysis on QC observations that are not QC deficiencies.

Paragraph .74 of the standard requires that the nature, timing, and extent of the root cause analysis be commensurate with the nature, severity, and pervasiveness of the QC deficiency. This provision did not draw comment and was adopted as proposed.

A QC deficiency that could affect multiple engagements may require more urgent root cause analysis, depending on the circumstances. To illustrate, a QC

deficiency related to a firm's approach to testing business combinations would be more urgent if a firm's clients regularly enter into such transactions. Taking into account the nature, severity, and pervasiveness of the QC deficiency, root cause analysis may be performed at different points in time or, depending on the size and nature of the firm, operate as more of a continual process. At times, it might be effective to combine similar QC deficiencies and perform root cause analysis on them collectively rather than on an individual basis.

In some instances, the causal factors may be relatively apparent and therefore require less analysis than in a situation where the cause of the deficiency is complex and requires significant investigation and analysis. As previously mentioned, there may be multiple causes contributing to a QC deficiency. Generally, the more thorough the analysis, the more likely the causal factors will be identified and the greater the likelihood that a firm could design and implement remediation efforts that will be effective in preventing similar QC deficiencies from occurring again.

It is important for firms to have well-defined processes in order to perform sufficient root cause analysis. The better delineated the underlying processes, the less work that may be necessary to determine why the QC deficiency occurred.

ii. Remedial Actions (QC 1000.75)

The requirement to design and implement timely remedial action for QC deficiencies did not attract comment and was adopted as proposed.

The timing of a firm's efforts to design and implement remedial actions depends on the results of the firm's root cause analysis and the nature, severity, and pervasiveness of the QC deficiency. The Board expects a firm to respond in a manner that would mitigate the occurrence of additional QC deficiencies related to similar underlying causes.

In some circumstances, due to the extent of remedial actions necessary to address the QC deficiency, a firm might design and implement temporary remedial actions until permanent actions can be designed and implemented. For example, a firm could design and implement supplemental audit practice aids to address QC deficiencies until the firm is able to revise its comprehensive audit methodology. In some situations, a complex QC deficiency may result in the firm developing a multi-step plan with milestones necessary to be

achieved as the firm designs and implements its remedial actions.

In other situations, the extent of remedial actions the firm needs to take to address a particular QC deficiency may be reduced by other compensating responses that the firm has in place. If the remedial actions, including any relevant compensating responses, have been tested and found effective in addressing the issue, the firm might determine, based on the facts and circumstances, that no further remedial action is necessary.

The process of identifying QC observations, determining QC deficiencies, performing root cause analysis, and designing and implementing remedial actions is iterative. For example, a firm may learn information from performing root cause analysis that may identify issues that would have been relevant when evaluating a different QC observation had such information been known at the time. If this were to occur, a firm would further evaluate the other QC observation to determine if a QC deficiency exists based on this new information. As another example, the work entailed in a root cause analysis could potentially help a firm identify other quality objectives that are not being met. To illustrate, the firm's root cause analysis may show that a lack of training caused deficiencies in a complex audit or accounting area that is common to the firm's engagements, and may also lead to the identification of other problems in the same area, such as inadequate audit methodology or a missed consultation due to the lack of a well-understood, robust consultation process.

PCAOB oversight activities have identified that some firms evaluate positive quality events associated with engagements where no engagement deficiencies were identified. For example, certain procedures, techniques, or voluntary practice aids may have contributed to an engagement performed in accordance with applicable professional and legal requirements. These firms use the information obtained from such evaluations to assess the actions of individuals on engagements with deficiencies, ultimately highlighting potential actions to prevent future engagement deficiencies. The Board believes that evaluating positive outcomes could contribute to the success of the firm's root cause analysis and remediation efforts. Therefore, the standard includes a note highlighting that it may be beneficial for firms to consider actions, behaviors, or conditions that resulted in positive

³⁰³ See June 2014 SAG Briefing Paper at 2.

³⁰⁴ See *Staff Inspection Brief*, Vol. 2017/4: *Preview of Observations from 2016 Inspections of Auditors of Issuers* (Nov. 2017), at 16, available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/inspections/documents/inspection-brief-2017-4-issuer-results.pdf?sfvrsn=c216d8a7_0.

outcomes, such as where aspects of the firm's QC system operated effectively or where no engagement deficiencies were identified for individual engagements.

In some circumstances, a firm may determine the root cause of a QC deficiency is related to the use of a resource or service provided by a third-party provider. If this were to occur, under the standard, the firm is responsible for addressing the effect of the deficiency on its QC system. This could include, among other things, working with the third-party provider to design and implement remedial actions or deciding to end the relationship with the third-party provider and, as part of the firm's remedial actions, revising its policies and procedures in the area affected. Irrespective of the approach taken and the extent of participation by third parties, the firm remains responsible for its QC system.

If a firm belongs to a network and uses network resources or services to enable the operation of the firm's QC system or the performance of its engagements, a root cause of a QC deficiency could be related to the network resource or service. Similar to a firm's use of resources or services

provided by a third-party provider, a firm is responsible for addressing the effect of the deficiency on its QC system regardless of whether the remedial actions taken by the firm are coordinated with the network or designed and implemented exclusively by the firm. Further, the firm remains responsible for determining whether the actions taken by the network sufficiently remediate the QC deficiency.

Under the standard, firms are able to design their approach to conducting root cause analysis and developing remedial actions. Firms' approaches will vary based on the nature and circumstances of the firm and its engagements. In addition, approaches will likely change as new technologies become available and other techniques develop.

k. Monitoring the Implementation and Operating Effectiveness of Remedial Actions (QC 1000.76)

The requirement to monitor the implementation and operating effectiveness of remedial action for QC deficiencies did not attract comment and was adopted as proposed.

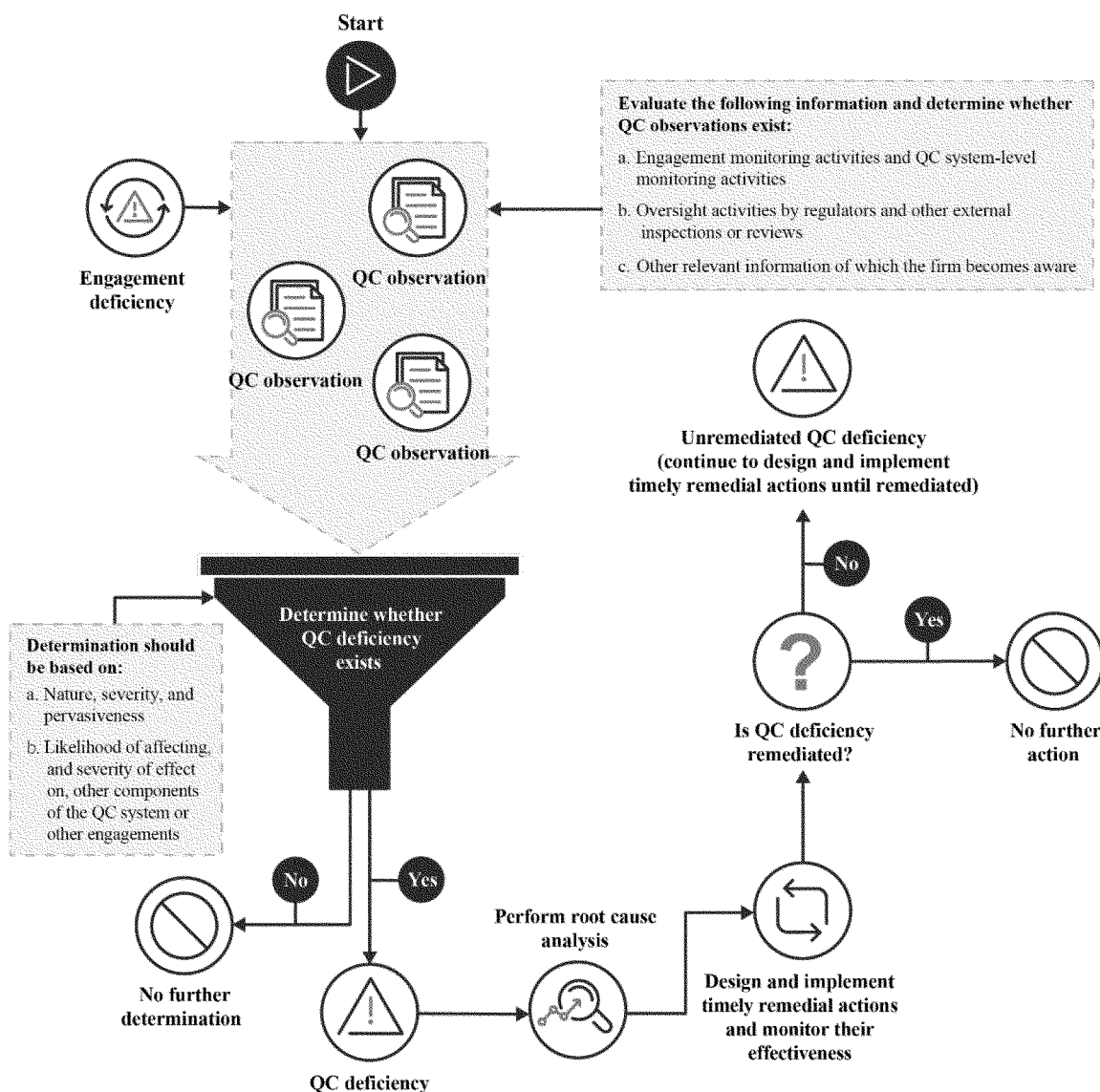
Under the final standard, a firm monitors the effectiveness of its remedial actions through engagement monitoring activities and/or QC system-level monitoring activities, depending on the nature of the QC deficiency. If a firm determines the remedial actions were not properly implemented or operating effectively, the firm would be required to take timely actions until the monitoring activities indicate the QC deficiency was remediated. Timely actions could include, among others, one or more of the following:

- Adjusting the implemented remedial actions;
- Designing and implementing additional remedial actions; or
- Performing additional root cause analysis to determine if other causes exist and, if so, designing and implementing remedial actions to address such causes.

Once additional actions are taken, a firm is required to perform monitoring activities on such changes to determine whether the QC deficiency was remediated.

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Determining the Existence of and Remediating QC Deficiencies



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2. Current PCAOB Standards

Current PCAOB QC standards require firms to establish policies and procedures to provide the firm with reasonable assurance that the policies and procedures relating to each of the other QC elements are suitably designed and are being effectively applied.³⁰⁵ The standards also address how a firm implements the monitoring element of a QC system in its accounting and auditing practice.³⁰⁶ The standards discuss various monitoring procedures that a firm may perform, such as reviewing engagements before or after the engagement reports are issued,

reviewing selected administrative and personnel records pertaining to the QC elements, considering systemic causes of findings that indicate improvements are needed, determining corrective actions, and following up to ensure that any necessary modifications are made to the firm's QC policies and procedures on a timely basis.³⁰⁷ Although current PCAOB QC standards provide that monitoring procedures taken as a whole should enable firms to obtain reasonable assurance that their QC systems are effective,³⁰⁸ there are no express obligations for firms to perform any specific types of monitoring.

Evaluation of and Reporting on the QC System

1. QC 1000

a. Annual Evaluation of the Effectiveness of the QC System (QC 1000.77)

A firm's evaluation of the results of its monitoring and remediation process helps the firm identify the areas within the QC system that are designed, implemented, and operating effectively, as well as areas that require attention. This perspective will assist firm leadership in allocating resources to address QC deficiencies and provide them with a basis for communicating to others—within or outside the firm—the status of the firm's QC system.

Current PCAOB QC standards do not require such an evaluation. The Board

³⁰⁵ See QC 20.20.

³⁰⁶ See generally QC 30.

³⁰⁷ See QC 30.03; QC 30.06.

³⁰⁸ See QC 30.03.

understands that some firms already evaluate their QC systems, either voluntarily or in response to other requirements.³⁰⁹ However, not all firms evaluate their QC systems, and those that do may not apply the same degree of rigor.

i. Evaluation Requirement

The proposed standard included a requirement for the firm to evaluate annually whether its QC system is effective, is effective except for one or more unremediated QC deficiencies that are not major QC deficiencies, or is not effective (*i.e.*, one or more major QC deficiencies exists). Pursuant to proposed paragraph .07c, firms that were not required to implement and operate a QC system at any time within the previous 12 months would not be subject to the requirement to evaluate and report on their QC system.

Some commenters expressed support for the proposed annual evaluation requirement. However, several commenters suggested that the Board conform the terminology to ISQM 1, such that the conclusions reached in evaluating the QC system would be the same under both standards. Some commenters expressed concern about the potential for stakeholder confusion because the criteria and terminology used in QC 1000 differ from ISQM 1. One commenter expressed concern that the more stringent criteria of QC 1000 would create a competitive disadvantage.

One commenter recommended that the Board eliminate the middle category (effective except for one or more unremediated QC deficiencies that are not major QC deficiencies), so that a firm's QC system would be evaluated as either effective or not effective based on whether any unremediated major QC deficiencies exist as of the evaluation date, such that the reasonable assurance objective has not been achieved. The commenter analogized to ICFR reporting, where management is only required to report material weaknesses.

The Board adopted the evaluation requirements as proposed. The Board does not believe there is any likelihood of confusion among external stakeholders arising from differences in evaluation criteria between QC 1000 and ISQM 1 because, under the final PCAOB standard, the conclusion reached about the effectiveness of a firm's QC system is not required to be made public. The same is true under ISQM 1. Therefore, if a firm were to

evaluate its QC system under both standards and reach different conclusions, market participants would be unaware of that fact unless the firm chose to make the results of its evaluation public (in which case, it could also choose to provide an explanation of the difference). Additionally, while ISQM 1 requires communication to those charged with governance about how the system of quality management supports the consistent performance of quality audit engagements, QC 1000 does not require any such communication to the audit committee.³¹⁰ Firms would of course be free to discuss the evaluation of their QC system with the audit committee, potentially as part of the report required under listing standards that may apply to the issuer.³¹¹ The Board believes most audit committee members are already well acquainted with reviewing information prepared under different frameworks, *e.g.*, financial statements prepared under U.S. GAAP and under IFRS, and could readily understand that the more stringent criteria under QC 1000 could lead to a different conclusion about the effectiveness of the QC system.

Similarly, the Board believes that firms that are required to perform multiple QC system evaluations will be able to train their personnel and acquire other resources as necessary to avoid confusion among internal stakeholders and perform the evaluation under QC 1000 appropriately. A firm will be subject to both QC 1000 and other QC standards only if it is performing audits under multiple sets of auditing standards. Just as such firms manage the differences in audit requirements and methodology associated with different auditing standards, the Board believes they will be capable of managing differences in the QC system requirements under QC 1000 and other QC standards, including differences in the criteria and terminology used in evaluating the QC system.

The Board also believes that requiring three categories for the QC system evaluation, as proposed—effective, effective except for one or more unremediated QC deficiencies that are not major QC deficiencies, and ineffective—will result in a more rigorous QC system evaluation, a greater incentive for firms to address QC deficiencies promptly, and more detailed and informative reporting to the PCAOB. Given that reporting is only

to the PCAOB, the Board does not believe an analogy to management's public reporting regarding ICFR, where only material weaknesses are required to be reported, is appropriate.

Firms will be required to perform an evaluation of their QC system annually. The firm's evaluation is based on data and evidence provided by the firm's monitoring and remediation activities. An annual evaluation will provide leadership with timely information to facilitate an effective feedback loop.³¹² This approach highlights the importance of the QC system in driving continuous improvement in firms' ability to perform compliant engagements on a consistent basis. The evaluation requirement will drive firms to collect and analyze the results of their monitoring and remediation processes in order to identify deficiencies and will provide an additional incentive for firms to focus on areas requiring the most immediate attention and improvement.

The evaluation requirement also reinforces the responsibility and accountability of leadership for the firm's QC system.³¹³ As discussed above, the individual charged with ultimate responsibility and accountability for the QC system as a whole will be accountable for the annual evaluation, and both that individual and the individual charged with operational responsibility and accountability for the QC system as a whole will be required to certify the firm's annual report regarding the evaluation of its QC system.³¹⁴ The Board believes this will send a clear message about the importance of the evaluation and incentivize firm leadership to take ownership of both the annual evaluation of the QC system and the results.

While the Board adopted as proposed a requirement for annual evaluation of the QC system, it made some changes in response to commenter input, as described below.

ii. Evaluation Frequency and Date

The proposed standard would have required the firm to evaluate its QC system annually as of November 30 and conclude on whether any unremediated QC deficiencies (including major QC deficiencies) exist as of that date.

³¹² Firms could decide to evaluate the QC system more frequently than required under the standard. For example, a firm with one or more major QC deficiencies may decide to perform a mid-year evaluation to gauge the effectiveness of its remedial actions.

³¹³ See QC 1000.13–.17.

³¹⁴ See QC 1000.14c.–d. and .15b.

³⁰⁹ See, *e.g.*, NYSE Listed Company Manual, Section 303A.07(b)(iii)(A); Section 2(d) of Article 13, Regulation (EU) 537/2014.

³¹⁰ See Reporting to the audit committee, discussed below.

³¹¹ See NYSE Listed Company Manual, Section 303A.07(b)(iii)(A).

One commenter, an investor-related group, supported the proposed November 30 evaluation date and opposed allowing firms to set their own reporting date.

Many commenters, generally firms and firm-related groups, suggested that firms should be permitted to choose their own evaluation date, primarily because it would enable them to choose a date based on their own operating and business cycle or inspection cycle. These commenters also noted other considerations, such as alignment with the firm's fiscal year end or the date already chosen for the evaluation required under ISQM 1. Several commenters suggested that firms should be able to choose a date that would allow them sufficient time to perform root cause analysis, remediate identified issues, and test the effectiveness of their remediation efforts. One commenter noted that firms could choose a date with a view to enabling real-time conversations with audit committees. Another commenter suggested that additional flexibility on the evaluation date would enhance the scalability of the standard. Some commenters stated that requiring a specific evaluation date could lead firms to perform assessments twice a year. Several commenters also raised a concern about potential resource limitations in performing the evaluation on the timetable the Board proposed.

Other commenters suggested various options for potential alternative evaluation dates:

- March 31, on the basis that it is better aligned with a natural business cycle for many firms or aligns with the Form 2 reporting date. (These commenters generally preferred allowing firms to choose their own evaluation date over a mandated date applicable to all firms and suggested March 31 as a second-best approach.)
- September 30, which would allow firms to report to the PCAOB by November 15 and, in turn, report to audit committees before the end of the calendar year.
- September 30 or October 31, if the proposed January 15th reporting date is implemented, to allow additional time to complete reporting.
- February 28, to allow reporting by April 1, in advance of the April/May proxy season.
- A window, for example, November to March, within which firms could choose a date.

Taking into account commenter feedback on the proposed evaluation date of November 30, the evaluation date was revised to September 30 for all firms. The Board believes this earlier

date addresses commenter concerns that the November 30 date would have caused potential resource limitations during the traditional busy period for many firms. Further, the Board believes an evaluation date of September 30 would provide the firm with enough time to identify and potentially remediate any QC deficiencies identified from the most recent calendar year-end engagements, which might not be possible if an earlier date were selected.

As summarized above, some firms expressed concern that a firm that has already chosen its evaluation date under ISQM 1 would be required to perform two QC system evaluations per year since the PCAOB's evaluation date differs from ISQM 1's. The Board believes firms can build on work already done for the purpose of complying with the requirements of one QC standard in performing the other, to the extent applicable. However, since the nature of the two evaluations is inherently different (e.g., the determination of major QC deficiencies, the differing definitions of QC deficiency under QC 1000 vs. deficiency under ISQM 1), the Board believes that there would always be some differences between the evaluation required under QC 1000 and the evaluation required under ISQM 1. While there could be additional costs associated with multiple evaluations if a firm chose to have separate evaluation dates for purposes of QC 1000 and other QC standards to which it is subject, firms would be free to change their evaluation date under other QC standards so that the evaluation dates coincide.

The proposed standard also included a note clarifying what unremediated means in the context of this requirement: remedial actions that completely address the QC deficiency have not been fully implemented, tested, and found effective. While this note did not draw specific comment, one commenter suggested that the framework afforded by section 104(g)(2) of Sarbanes-Oxley, which the commenter said focuses on substantial good faith progress instead of complete remediation, is necessary and should be retained. The Board disagrees as, in its view, the two provisions serve fundamentally different purposes and a different approach is appropriate for firm evaluation and reporting under QC 1000.

Sarbanes-Oxley section 104(g)(2) governs the circumstances under which the PCAOB is permitted to make portions of an inspection report dealing with quality control criticisms and potential defects public. It forbids

publication if the criticisms or defects "are addressed by the firm, to the satisfaction of the Board," not later than 12 months after the date of the report. In describing its process for determining whether a matter has been addressed to its satisfaction, the Board indicated that a "favorable Board determination reflects the Board's assessment that the firm has demonstrated substantial, good faith progress toward achieving the relevant quality control objectives, sufficient to merit the result that the criticisms remain nonpublic. A favorable determination does not necessarily mean that the firm completely and permanently cured any particular quality control defect."³¹⁵

By contrast, reporting on Form QC is simply factual: as of the evaluation date, has each identified QC deficiency been fully remediated or not? Under QC 1000, firms will perform a self-evaluation, based on the process and criteria set forth in the standard. This is very different from the process by which the Board determines whether a matter has been remediated to its satisfaction for purposes of section 104(g)(2),³¹⁶ not least because it involves the firm's self-assessment rather than the Board's judgment. Moreover, the Board does not believe the consequences of a firm reporting an unremediated QC deficiency to the PCAOB would be the same as the consequences of the PCAOB publishing QC criticisms in an inspection report; in particular, the Board does not believe that the legislative policy choice reflected in section 104(g)(2), which, as the Board has said, favors "the correction of quality control problems over the exposure of them,"³¹⁷ applies in this context, given the nonpublic nature of the Form QC reporting. Accordingly, the Board adopted the note to paragraph .77 as proposed.

b. Determining Whether Major QC Deficiencies Exist (QC 1000.78)

The standard requires firms to evaluate unremediated QC deficiencies as of the evaluation date to determine whether major QC deficiencies exist. While the identification of QC deficiencies will be an ongoing process throughout the year, the determination of whether any of those QC deficiencies, alone or in combination, constitute major QC deficiencies will be required only as part of a firm's annual evaluation of its QC system.

³¹⁵ PCAOB Rel. No. 104-2006-077 at 6.

³¹⁶ See PCAOB Rule 4009, *Firm Response to Quality Control Defects*.

³¹⁷ PCAOB Rel. No. 104-2006-007 at 2.

i. Definition of a Major QC Deficiency

The proposed standard provided that a major QC deficiency was “an unremediated QC deficiency or combination of unremediated QC deficiencies, based on the evaluation under paragraph .78, that severely reduces the likelihood of the firm achieving the reasonable assurance objective or one or more quality objectives.” One commenter supported the concept of major QC deficiency. However, a number of commenters expressed concern with that proposed definition:

- Several commenters expressed concern that the definition could cause a firm to come to a different conclusion about its QC system during the annual evaluation process under QC 1000 than the conclusion a firm may reach under ISQM 1 and suggested that the definition be revised to include the concepts of severe and pervasive, similar to the concepts that appear in relation to the evaluation of QC deficiencies under ISQM 1.
- One commenter stated that it was unclear why a new term, “major QC deficiency,” would be necessary and questioned the need for a reference to a threshold other than “achieving reasonable assurance.”
- Another commenter was concerned that the concept of major QC deficiency, which other QC standards do not use, will redirect time and resources to analyzing the level of a deficiency instead of the important elements to remediate the deficiency such as root cause analysis and implementing timely changes to a firm’s system.
- Another commenter stated that the phrase “severely reduces the likelihood” in the definition of major QC deficiency is vague and not sufficiently defined in the proposed QC standards and suggested that the phrase be replaced with the phrase “prevents the firm from concluding.”

The Board considered the commenter feedback and determined to adopt this language as proposed. The Board agrees it is possible that firms could reach different conclusions as to the effectiveness of their QC system under QC 1000 and ISQM 1 or SQMS 1. However, the concept of severe and pervasive, which commenters suggested be incorporated in the definition, appears in the factors for firms to consider when determining the existence of a major QC deficiency (see paragraph .78b. below). The Board believes that including this concept in the factors clarifies the process firms will need to go through in making their

determination of whether a major QC deficiency exists.

The defined term “major QC deficiency” is unique to QC 1000, but the concept it embodies—that the QC system does not provide the firm with reasonable assurance that the objectives of the QC system have been met—is not, and appears in both ISQM 1 and SQMS 1. Accordingly, the Board does not believe that phrasing the requirements as it has, including the use of a defined term, will require a different evaluation process than if it had simply required a determination that the QC system was ineffective. The standard does not require the determination of major QC deficiencies to be performed at any time other than the evaluation date. However, firms may choose to perform such an analysis ahead of the annual evaluation date to enable sufficient time to design, implement, and test remedial actions related to the QC deficiencies that have the greatest potential impact on the QC system.

As with the defined term “QC deficiency,” the defined term “major QC deficiency” is analogous to a term in COSO’s integrated framework, major deficiency, which includes the concept of “severely reduces the likelihood.” The Board believes that this concept is already well-understood by firms.

Another commenter expressed concern that a major QC deficiency would exist if there was a severely reduced likelihood that the firm did not achieve a single quality objective, even when the firm had in fact achieved the reasonable assurance objective. In the Board’s view, this concern is more theoretical than real. The quality objectives in QC 1000 relate to compliance with applicable professional and legal requirements in each component of the QC system and in the aspects of the firm’s practice that are addressed by each component. Failing to achieve such a quality objective implies that the reasonable assurance objective has not been achieved. Some quality objectives, particularly in the resources component, also relate to compliance with the firm’s policies and procedures. These quality objectives are directed to the QC system itself: compliance with policies and procedures is necessary for the QC system to operate as designed. While failure to comply with firm policies and procedures does not necessarily imply failure to comply with applicable professional and legal requirements, it does mean that the QC system is not operating as designed, which may raise questions about the level of assurance it provides.

In response to commenter feedback regarding the proposed concept of presumed major QC deficiencies (discussed in the next section), the lead-in language of paragraph .78 was revised to clarify that the factors in paragraph .78b are to be applied by the firm both (i) when a presumption arises that a major QC deficiency exists and the firm attempts to rebut the presumption, and (ii) in instances where no presumption arises.

ii. Presumed Major QC Deficiency (QC 1000.78.a)

The proposed definition of a major QC deficiency provided for two circumstances that would be presumed to evidence a major QC deficiency. These circumstances included an unremediated QC deficiency or combination of unremediated QC deficiencies that:

- *Relates to the firm’s governance and leadership that affect the overall environment supporting the operation of the QC system.* Firm governance and leadership establish the environment that determines how firm personnel carry out responsibilities for the operation of a firm’s QC system and the performance of its engagements. Because of the pervasive impact of leadership and the “tone at the top,” one or more unremediated QC deficiencies related to firm governance and leadership that affect the overall environment supporting the operation of the QC system would almost always severely reduce the likelihood of the firm achieving the reasonable assurance objective or one or more quality objectives.
- *Results in or is likely to result in one or more significant engagement deficiencies in engagements that, taken together, are significant in relation to the firm’s total portfolio of engagements conducted under PCAOB standards.* A significant engagement deficiency exists when (1) the engagement team failed to obtain sufficient appropriate evidence in accordance with the standards of the PCAOB or failed to perform interim review or attestation procedures necessary in the circumstances, (2) the engagement team reached an inappropriate overall conclusion on the subject matter of the engagement, (3) the engagement report is not appropriate in the circumstances, or (4) the firm is not independent of its client.³¹⁸ An unremediated QC deficiency that would likely result in one or more of these deficiencies in engagements that, taken together, are significant in relation to the firm’s total portfolio of engagements

³¹⁸ See Notes to AS 1220.12, .17, .18B.

conducted under PCAOB standards would give rise to a presumption that a major QC deficiency exists. The definition included examples of quantitative and qualitative criteria that may signal such significance.

One commenter argued that the proposed presumption regarding deficiencies in the governance and leadership component was unnecessary, on the basis that not every deficiency in governance and leadership was necessarily a major QC deficiency. Other commenters expressed concern that the circumstances presumed to evidence a major QC deficiency remove the auditor's ability to apply professional judgment. Another commenter suggested that the presumptions could be replaced with indicators of a major QC deficiency, similar to how AS 2201 treats material weaknesses. Another commenter stated that it is not appropriate to include in the proposed definition circumstances when a major QC deficiency is presumed to exist because the factors provided in paragraph .78 are sufficient to make the evaluation of whether a QC deficiency is a major QC deficiency. Another commenter suggested that these presumed major QC deficiencies could be relocated from the definition and into paragraph .78 and achieve the same objective.

The Board considered the commenter feedback. However, as described above, the Board continues to believe that because of the pervasive impact of leadership and the "tone at the top," one or more unremediated QC deficiencies related to firm governance and leadership that affect the overall environment supporting the operation of the QC system would almost always severely reduce the likelihood of the firm achieving the reasonable assurance objective or one or more quality objectives—that is, would almost always result in a major QC deficiency.

The Board also noted that, consistent with the proposal, the presumptions are not conclusive and can be rebutted by the firm in appropriate circumstances. The note to paragraph .78a clarifies that in order to rebut a presumption that a major QC deficiency exists, a firm must demonstrate, by taking into account both of the factors in paragraph .78b. (including all of the listed examples in paragraph .78b.(1)), that a major QC deficiency does not exist.³¹⁹ The

standard thus allows for circumstances in which a deficiency related to one of the presumptions does not amount to a major QC deficiency, and creates an opportunity for firms to exercise professional judgment in deciding whether to attempt to rebut the presumption and, if so, how to apply the paragraph .78b factors. However—appropriately, in the Board's view—the presumptions shift the burden of proof to the firm, which will have to demonstrate that circumstances generally reflecting a major QC deficiency do not constitute a major QC deficiency in its case. The Board believes the term "presumption" achieves this burden shifting more clearly than "indicators" or other terms would do.

The Board agrees with the commenter that suggested that the presumed major QC deficiencies should not be included in the definition of major QC deficiency and have taken another commenter's suggestion to relocate the presumption to paragraph .78. Accordingly, the Board made the following revisions to paragraph .78:

- Relocated the circumstances presumed to evidence a major QC deficiency from the definition into paragraph .78a, so they are explicitly part of the process of determining whether a major QC deficiency exists.
- Included a note to clarify what the firm has to demonstrate in order to rebut the presumption that a major QC deficiency exists.

Importantly, the circumstances where a major QC deficiency is presumed to exist are not an exhaustive list of possible major QC deficiencies. For example, any deficiency that requires significant effort and resources to remediate may be a major QC deficiency.

One firm requested clarification of the relationship between the definitions of "engagement deficiencies" and "significant engagement deficiencies." As is evident from their respective definitions, significant engagement deficiencies are a subset of engagement deficiencies. QC 1000 defines an engagement deficiency as "an instance of noncompliance with applicable professional and legal requirements by the firm, firm personnel, or other participants with respect to an engagement of the firm, or by the firm or firm personnel with respect to an engagement of another firm." As the footnote to paragraph .78 of the standard provides, "A significant engagement deficiency exists when (1) the

engagement team failed to obtain sufficient appropriate evidence in accordance with the standards of the PCAOB or failed to perform interim review or attestation procedures necessary in the circumstances, (2) the engagement team reached an inappropriate overall conclusion on the subject matter of the engagement, (3) the engagement report is not appropriate in the circumstances, or (4) the firm is not independent of its client. *See, e.g.,* Notes to AS 1220.12, .17, .18B."

iii. Factors for Consideration

To help firms make the determination of whether a major QC deficiency exists, the standard provides factors on which to base the determination, which assist firms in applying the definition. Several commenters expressed general support for the proposed factors, and the Board adopted them as proposed.

The Board did not receive comments on the examples that illustrated the proposed factors, and adopted this aspect of the proposal substantially as proposed, with one addition, in a renumbered paragraph .78b.(1)(d). The added example relates to the persistence of an unremediated QC deficiency or combination of unremediated QC deficiencies over time. Through its oversight activities the PCAOB has observed repeat or persistent criticisms—appearing in consecutive inspections, or occurring consistently over multiple years, even if not every year—which the Board believes may be indicative of a problem so pervasive and/or so severe that the firm has been unable to effectively remediate it, or of significant failures in the firm's remediation process. Firms will need to consider whether and how the existence of a persistent unremediated QC deficiency or combination of unremediated QC deficiencies year over year might indicate the existence of a major QC deficiency.

Under the standard, the factors for determining whether a major QC deficiency exists are:

- *The severity and pervasiveness of the unremediated QC deficiency or combination of unremediated QC deficiencies.* A firm assesses an unremediated QC deficiency, considering both quantitative and qualitative implications. For example, a firm will assess how many of the components of its QC system, quality objectives, and quality responses are affected by the deficiency, the number of root causes, and the number of affected engagements or engagements likely to be affected in the future, as well as the impact on those engagements, including engagements

³¹⁹ When circumstances exist that are presumed to evidence a major QC deficiency, but the firm demonstrates that it does not have a major QC deficiency, the firm will be required to disclose the basis for its determination in its report to the PCAOB on Form QC, as discussed further below.

See Form QC, Report on the Evaluation of the Firm's System of Quality Control, Item 2.5.

where the opinion was not appropriately supported or the financial statements or management's internal control assessment had to be revised or restated. The firm would also consider the implications of the deficiency for the QC system overall, based on ways in which the design or operation of other aspects of the QC system may be affected, the pervasiveness of the root causes, and the risk of the firm issuing inappropriate engagement reports or otherwise performing deficient engagements in the future. Viewed this way, for example, an unremediated QC deficiency that affects engagements only in a single industry, where the firm has few clients and no intention to acquire more and the engagements represent an

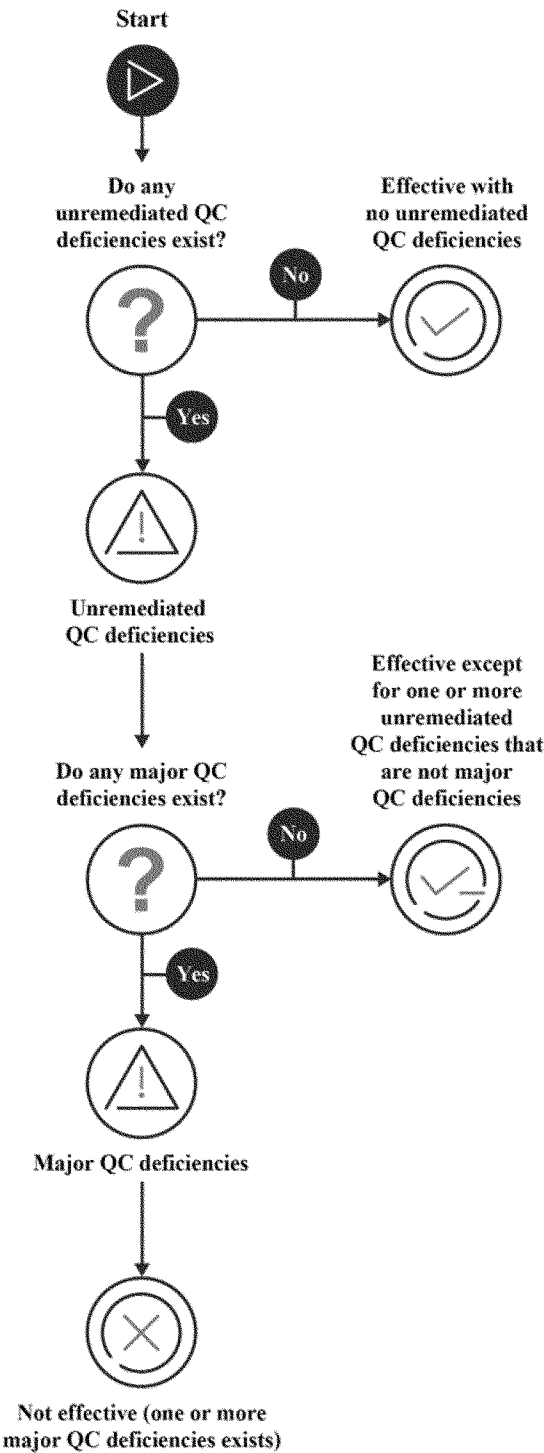
insignificant portion of the firm's total portfolio of engagements under PCAOB standards, is less likely to be severe or pervasive. The Board views the concepts of severity and pervasiveness as overlapping and the factors in paragraph .78b.(1) that indicate the severity and pervasiveness of an unremediated QC deficiency, or combination of unremediated QC deficiencies, represent both aspects. The standard does not require the firm to determine that an unremediated QC deficiency is both severe and pervasive in order for it to constitute a major QC deficiency, nor is the list of examples exhaustive.

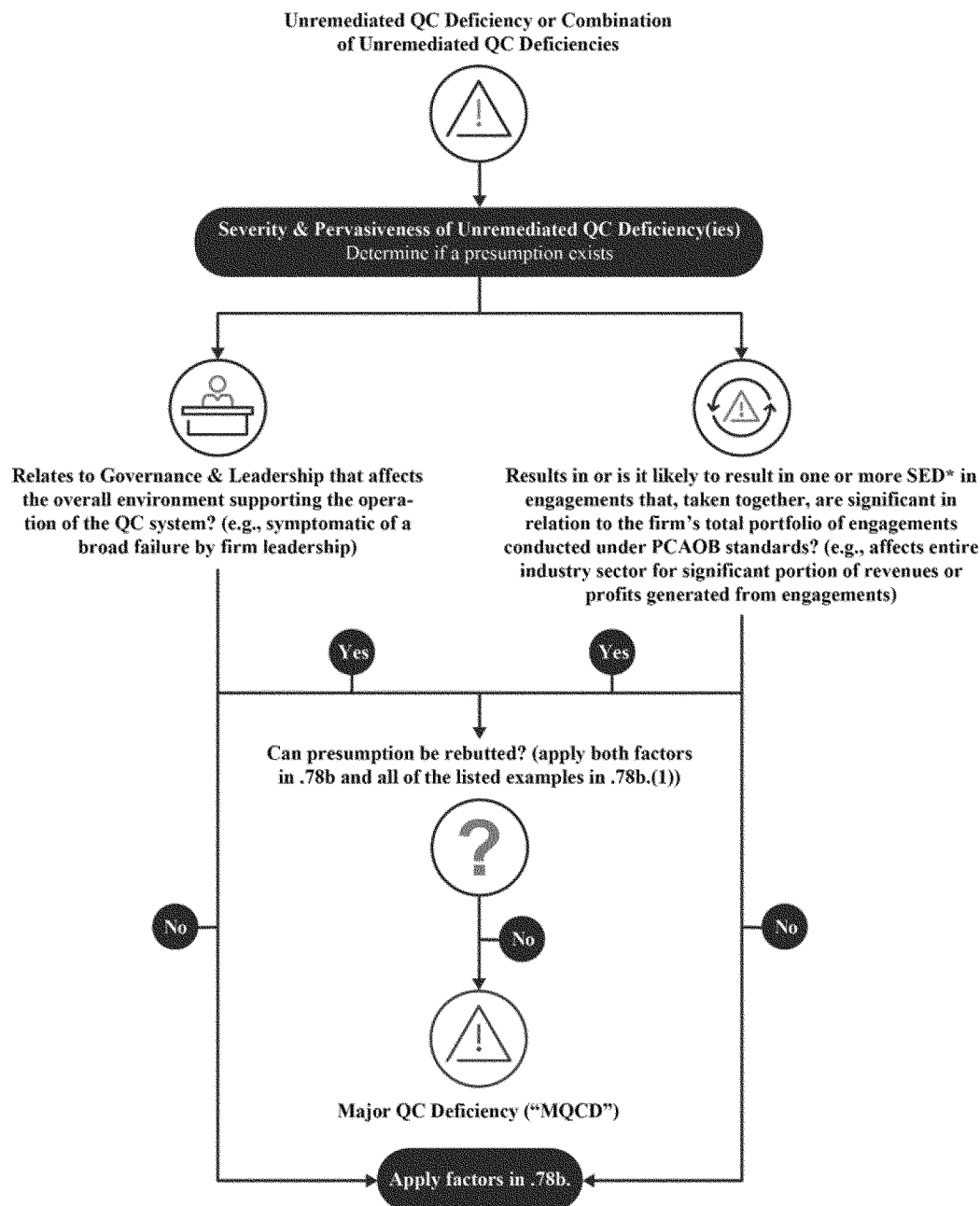
- *The extent to which remedial actions have been implemented, tested,*

and found to be effective. Before the annual evaluation date, a firm may implement remedial actions that reduce the severity or pervasiveness of an unremediated QC deficiency. To illustrate, if a firm identifies an issue with its audit software, it could develop a temporary "work around" to mitigate the unremediated QC deficiency until a permanent solution is employed. For this factor to be relevant for a firm when determining whether a major QC deficiency exists as of the annual evaluation date, the remedial actions have to be tested and the results have to show that such remedial actions are operating effectively.

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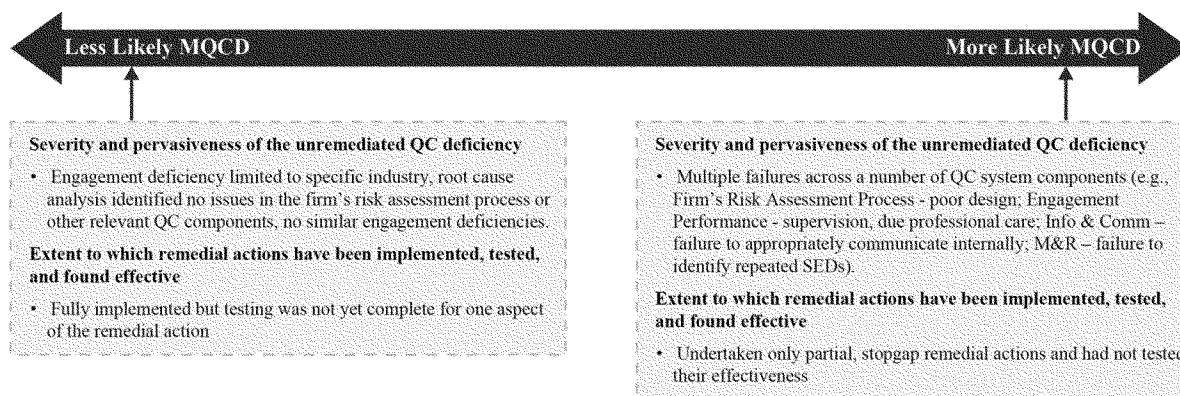
Annual Evaluation of the Firm’s QC System



Determine Whether a Major QC Deficiency(ies) Exists

*SED – Significant engagement deficiency. A significant engagement deficiency exists when (1) the engagement team failed to obtain sufficient appropriate evidence in accordance with the standards of the PCAOB or failed to perform interim review or attestation procedures necessary in the circumstances, (2) the engagement team reached an inappropriate overall conclusion on the subject matter of the engagement, (3) the engagement report is not appropriate in the circumstances, or (4) the firm is not independent of its client.

Example Considerations Relevant to Determining Major QC Deficiency



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c. Firm Reporting on QC System Evaluation (QC 1000.79-.80)

i. Reporting to the PCAOB

(1) Annual Reporting

Under the proposal, firms were to report to the Board annually the outcome of the evaluation of the firm's QC system with respect to any period during which the firm was required to implement and operate the QC system. Many commenters supported the proposed annual reporting requirement. However, one commenter stated that this annual firm reporting would be of no meaningful incremental benefit to the PCAOB and has the potential to create an adversarial dynamic that would not promote audit quality or well serve investor protection goals. Another commenter suggested that if the required reporting on Form QC to the PCAOB would lead to follow-on requests from the PCAOB to furnish more detailed information as to specific findings, then confidentiality legislation may be an issue for firms. Other commenters argued that, because the PCAOB could obtain the same information through the inspections process, reporting to the PCAOB would be unnecessarily duplicative. Another commenter argued that all unremediated QC deficiencies should not have to be reported on Form QC, specifically commenting that the PCAOB already has the ability to access QC documentation for all registered firms to view this information. Another commenter suggested that the value of the report when not accompanied by independent attestation is likely to be limited.

The Board acknowledges that it has the ability to request from firms information relating to their QC systems. However, the Board continues to believe that annual reporting to the

Board will provide the PCAOB with important information about firm QC systems in a timely and structured way and will provide an effective and efficient means of gathering information about firm QC systems. Currently, only 14 of the approximately 1,600 registered firms are subject to annual inspection. Approximately 640 registered firms are required to be inspected on a triennial basis, of which approximately one third are inspected in any given year.³²⁰ Therefore, the Board does not believe that collecting firms' QC information during an inspection would provide timely information regarding the majority of registered firms' QC systems. Data collected by the PCAOB will inform its inspections process, including decisions about the selection of firms and engagements as well as focus areas to inspect and the nature and extent of its inspection procedures (both for QC processes and individual engagements), and will enable the PCAOB not only to make more refined data requests from the firms, but also to focus its inspection resources on those firms and engagements with the greatest risk. The Board believes that this will help better advance its investor protection mandate. Additionally, the Board believes that a formal reporting process will result in enhanced accountability of firm leadership for QC and an additional incentive for prompt remediation of identified QC deficiencies. While the standard does not require attestation over the firm's evaluation process, the Board believes that the requirements regarding the form, including required certifications, will provide sufficient incentive for firms to report accurately and completely (and enforcement remedies

³²⁰ The data were obtained from Audit Analytics and publicly available data from the PCAOB's Registration, Annual and Special Reporting (RASR) available at <https://rasr.pcaobus.org>.

will be available if they do not). The incremental effort for a firm to report its evaluation to the PCAOB will not be substantial, as the firm is simply communicating the results of its evaluation process and any related remediation activities, which it is required to conduct and document under QC 1000 in any case.

One firm suggested that the Board only require reporting to the PCAOB if a firm performed engagements in accordance with PCAOB standards during the one-year period ending on the evaluation date. The Board considered whether this change would be of significant benefit to firms and would further enhance the scalability of the standard. However, firms that are not currently performing engagements may have responsibilities with respect to past engagements.³²¹ Moreover, regardless of whether they are required to report the results of the annual evaluation, firms will still be required to perform an evaluation pursuant to QC 1000 in such a circumstance. On that basis, the Board believes that reporting would be valuable even for firms that did not perform an engagement during the year preceding the evaluation date, and that reporting should not constitute an undue burden.

(2) Reporting Mechanism: Form QC

As proposed and under the final rules, firms are required to report their annual QC evaluation on a new form, Form QC. Several commenters supported the use of a separate Form QC, with some of these commenters asserting that because firms should be allowed to select their own evaluation date, this would necessitate the use of Form QC, rather than an existing form such as Form 2. Another commenter supported the view that expanding Form 2 to incorporate QC information

³²¹ See, e.g., AS 2901; AS 2905.

was not favorable as this would make the form longer and more complex. The Board continues to believe that separate reporting on new Form QC remains appropriate. The contents of Form QC are the result of a separate evaluation process by a firm and the Board believes that it is simpler for the results of the annual evaluation to be reported on a separate form. In addition, as discussed in more detail above, QC 1000 requires firms to conduct an annual evaluation of their QC system as of September 30. The use of a separate Form QC for reporting the results of the annual evaluation will facilitate closer alignment of the timing of the reporting and the annual evaluation date. For example, the submission deadline for Form 2 is June 30, which is nine months after the annual evaluation date of September 30. Furthermore, Form 2 reporting is public and, as discussed in more detail below, Form QC will not be publicly available.

The proposal asked whether Form QC should be permitted to be filed in XML or another machine-readable format. In response, one commenter supported the PCAOB permitting widely accepted formats that support usability. Another commenter supported that the web-based system for submitting the information be navigable and easy to use. Reporting to the PCAOB will be done using the same platform as its other reporting forms (currently, its web-based RASR system and, in the future, potentially new means of information exchanges as the PCAOB continues to modernize its reporting technology aimed at simplifying and automating data collection, processing, and interoperability).

(3) Contents of Form QC

The contents of Form QC will address the matters listed in paragraphs .79–.80. In addition, Form QC will elicit certain information about the firm and the individuals responsible for the QC system, aggregated information about the items required to be reported in paragraph .80, the areas of QC to which any unremediated QC deficiencies relate, and a certification of the evaluation of the QC system by certain designated individuals (discussed below).

One firm asserted that the requirement to report unremediated deficiencies is at too granular a level to be meaningful. The Board considered several alternatives, including requiring firms to report to the Board on the outcome of the annual evaluation of the firm's QC system only when the firm identifies a major QC deficiency. While this approach could reduce some of the costs associated with preparing the

annual evaluation to the PCAOB, it would also significantly reduce the value of the reporting of the firm's annual evaluation to the PCAOB, as well as potentially affecting the rigor of the firm's evaluation process. As noted above, reporting on all unremediated QC deficiencies will inform various aspects of the Board's oversight activities. In addition, to the extent that reporting may increase firm leadership's focus on their responsibility and accountability for quality, reduced reporting would be less beneficial. Therefore, the Board decided that annual reporting to the PCAOB of the results of firms' annual evaluation of the QC system, including unremediated QC deficiencies, is the appropriate approach.

One commenter supported the inclusion of Item 4.1 of Form QC on whether the Board should inform a party of a subpoena for information on Form QC, but another commenter argued that it was unnecessary, may interfere with investigations, may create a potential ground for firms to sue the Board in the event notification did not occur, or potentially involve the PCAOB in private litigation. Because Form QC will be nonpublic, the Board believes that firms should be given the opportunity to request such notification, consistent with the PCAOB's treatment of the other nonpublic form filed with the PCAOB.³²²

An investor suggested firms should also affirm to the PCAOB on Form QC that any information that the firm voluntarily released (e.g., in transparency reports, audit quality reports, and CEO speeches) over the time period covered by Form QC was consistent with the state of their quality control system, as of the time of the voluntary disclosure. This commenter also suggested that the affirmation should be publicly available. An investor-related group suggested that firms should report publicly on Form QC how an independent QC board committee (established under paragraph .28 of QC 1000) carries out its responsibilities. As discussed in more detail below, Form QC will not be publicly available, so there would be no benefit to the public in adding this information to Form QC. However, the Board remains committed to finding additional ways of providing public disclosure to better inform investors about firms, and to that end, has separately proposed to amend Form 2 to identify whether the firm has an

external oversight function for the audit practice (established under paragraph .28 of QC 1000) and, if so, the identity of the person or persons and an explanation for the basis of the firm's determination that each such person is independent (including the criteria used for such determination) and the nature and scope of each such person's responsibilities.³²³

Some commenters indicated that there might be circumstances in which information required by Form QC may be restricted from disclosure by the operation of legal requirements (such as data protection laws). Two of these commenters suggested that the instructions to Form QC should include a provision found in other PCAOB forms allowing firms to decline to provide information if the firm believes that providing such information would violate non-U.S. law. Another commenter, while acknowledging that it was not aware of non-U.S. laws that would prohibit reporting the information required on Form QC, suggested that the Board state that firms would not violate the requirement to file Form QC if laws or regulations exist in the jurisdiction(s) of the firm that prevent compliance with this requirement.

The Board acknowledges that certain PCAOB forms include a general instruction for assertions of conflicts with non-U.S. law. In these circumstances, the instructions identify the specific parts and items within the form for which the firm may withhold responsive information on the basis that the firm could not provide such information without violating non-U.S. law. Form QC, however, calls for certain discrete information that the Board does not believe, and that no commenter has suggested, would be restricted from disclosure under non-U.S. law (e.g., the firm's name, the evaluation date, the overall conclusion of the firm's evaluation, the number of unremediated QC deficiencies, and for each unremediated QC deficiency, whether it is or is not major and the areas of the QC system to which it relates). Beyond that, Form QC requires firms to provide narrative information, including a description of each unremediated QC deficiency, the basis for the firm's QC deficiency determination, a summary of remedial actions, and the firm's major QC deficiency presumption analysis (if applicable). The Board believes that the narrative information required to be reported in Form QC can be provided at a sufficiently summarized level such that the reporting of such information

³²² See General Instructions 5 to PCAOB Form 1–WD, *Request for Leave to Withdraw from Registration*.

³²³ See PCAOB Rel. No. 2024–003 at 29.

by the firm would not require disclosure of information that could be restricted by legal requirements such as data protection laws. For example, if a firm reports an unremediated QC deficiency on Form QC, the Board believes that the firm could provide a description of the deficiency and a summary of the remedial actions taken and planned to be taken without violating non-U.S. law.

Some commenters suggested that the standard should clarify that firms submit Form QC in connection with an inspection under section 104 of the Sarbanes-Oxley Act and that Form QC should receive the same confidentiality protections of section 105(b)(5)(A) of the Act that other inspections-based documents and information receive. One of these commenters further suggested that the Board should make clear that all of Form QC and its contents benefit from the privilege established by section 105(b)(5)(A), regardless of how a deficiency has come to light. Another commenter suggested that the Board consider requesting firms to provide the information proposed to be in Form QC through the inspection process, and that such requests could be made at any time to facilitate the PCAOB's inspections. The commenter explained that under this suggested alternative approach, Part II and the related exhibits of Form QC could be removed and instead, the PCAOB could request this as part of the inspection process, to allow the information to be privileged under section 105(b)(5), while retaining the certification.

The Board does not believe that it is appropriate to specify that Form QC is provided in connection with an inspection. The obligation to furnish Form QC to the PCAOB does not derive from a request from PCAOB inspection staff; instead, that obligation arises expressly from paragraph .79 of QC 1000. And while Form QC, like other forms filed with the PCAOB (such as annual reports on Form 2), may be used to inform the PCAOB inspection process, that is not the only purpose of the form; it may be used, for example, in connection with PCAOB standard-setting processes, its economic and risk analysis, and its registration program, to name a few examples. Furthermore, Form QC submissions may not directly relate to an inspection. For example, triennially inspected firms are required to report on Form QC annually, including in years in which they are not subject to inspection. Firms that are no longer performing engagements making them subject to PCAOB inspection may still be required to report on Form QC in light of their post-issuance QC responsibilities, such as their audit

documentation retention obligations under AS 1215. Accordingly, the Board does not believe that Form QC is received by the Board in connection with an inspection for purposes of section 105(b)(5)(A) of the Act, though it notes, as discussed further below, that certain information contained within a Form QC may be subject to the protections of section 105(b)(5)(A).

(4) Reporting Date

The proposal contemplated that firms would have until January 15 of the year following the November 30 evaluation date to file Form QC. This provided firms 46 days from the evaluation date to the reporting date. As adopted, the standard provides that firms have until November 30 to report on Form QC to the PCAOB. This provides firms with 61 days after the evaluation date of September 30 to file Form QC. A general instruction was added to Form QC to clarify the reporting period covered by the firm's evaluation. The reporting period is the period beginning on October 1 of the year preceding the year in which Form QC is required to be filed (or, if a firm's obligation to implement and operate a QC system arises under paragraph .07a after October 1 of that year, the date on which that obligation arises) and ending September 30 of the year Form QC is required to be filed. Under this provision, the reporting period will generally be 12 months long, but will be shorter if the obligation to implement and operate the QC system arises mid-period (whether by virtue of the effective date of QC 1000 or the firm's otherwise becoming subject to the requirement to implement and operate the QC system).

Several commenters suggested a 90-day period from the evaluation date to the reporting date would be appropriate because this would allow for testing of controls that operate at the evaluation date, and allow firms to perform thorough and detailed evaluations. Several commenters suggested that additional time is required for Form QC preparation beyond 45 days to be able to compile relevant information, including information on remedial actions, with some commenters supporting a 60-day period that would align with the shortest due date applicable to issuers to report on their conclusion on internal control over financial reporting. Another commenter suggested that reporting should be in advance of the April/May proxy season, suggesting a reporting date of April 1 using an evaluation date of February 28. One commenter did not support a January 15 reporting deadline, suggesting that this would be close to

the conclusion of the audit and, if there are matters to be reported to the audit committee, would leave the audit committee with little time to consider and respond to the information before the due date of the issuer's Form 10-K. The commenter also suggested that for firms subject to both ISQM 1 and QC 1000, having different reporting dates would create unnecessary complexities for audit committees receiving reports under different standards and different points in time. Several commenters suggested that a January 15 reporting deadline would be challenging for many firms given the proximity to year-end holidays. One commenter suggested that coinciding the reporting date of January 15 with the PCAOB's inspection process should not be a key consideration for firms in determining the most appropriate date for their annual assessment.

The Board believes that extending the number of days from the evaluation date to the reporting date to 61 days will provide firms sufficient time to complete their evaluation and report to the PCAOB. In addition, the reporting date of November 30 as adopted is prior to the calendar year end and the traditional busy period for many firms, which the Board believes will further benefit firms in performing their evaluations.

ii. Form QC: Not Publicly Available

The proposed standard contemplated that Form QC would be nonpublic. Many commenters, including firms, supported requiring the contents of Form QC to be nonpublic. One firm commented that to require public reporting would be inconsistent with the balance that Congress struck in sections 104(g)(2) and 105(b)(5) of Sarbanes-Oxley. One commenter asserted that the PCAOB should not use rulemaking to cause firms to disclose quality control matters that the PCAOB is prohibited by Sarbanes-Oxley from disclosing or cause firms to otherwise disclose information that would be confidential under statute. Another commenter suggested that public disclosure of unremediated QC criticisms could allow companies that have a lower demand for audit quality to select a lower quality auditor.

Other commenters, generally investors and investor-related groups, objected to the lack of public disclosure. Two investors commented that the proposed disclosure to audit committees but not to the public leaves investors in the dark, and that disclosure requirements provide an effective incentive for remediation of identified quality control issues. Another

commenter asserted that if the PCAOB is permitted to compel firms to disclose quality control information to audit committees, then they expect that the PCAOB could also compel disclosure of such information to the public. The commenter suggested that QC disclosures only to audit committees may have unintended consequences for the public markets as companies will have more information regarding the quality of their auditors than individual investors. Some investors and investor-related groups commented that the proposal provides little public accountability with no mandated or meaningful disclosures about the operation of the QC system. Two investors and an investor-related group commented that firms furnish a statement of the quality control policies of the firm when registering with the PCAOB, however this information is not required to be updated and can quickly become out of date. Therefore, providing the public with additional disclosure about a firm's quality control system will act as an updating function.

One firm suggested that it would be difficult for the public to synthesize in a useful manner the information in Form QC without the right level of context. However, three investor-related groups did not support the view that partial disclosure of Form QC would result in potentially incomplete or misleading picture of a firm's QC system, and favored disclosing elements of Form QC and leaving to investors the assessment of the relative importance of the information. One of the investors further suggested a restructuring of Form QC that would allow confidential information to remain confidential while sharing decision-useful information with investors. Another investor suggested that investors would directly benefit from the disclosure of firm-identified deficiencies that omits PCAOB-identified deficiencies, further commenting that to the extent firms do not disclose any deficiencies to the public, investors may have concern that the system of quality control was not sufficient to proactively identify deficiencies.

The Board continues to recognize the desire of investors and other stakeholders for information related to audit quality and the effectiveness of firms' QC systems. But its ability to require firms to publicly disclose their QC deficiencies is subject to certain legal constraints imposed by Sarbanes-Oxley.

As a threshold matter, some or all of the unremediated QC deficiencies identified during a firm's annual evaluation may have been identified as

QC criticisms or potential defects during a PCAOB inspection.³²⁴ Furthermore, the Board believes that the QC deficiencies identified during PCAOB inspections are likely to be important information from the perspective of investors and other stakeholders, especially because PCAOB inspection teams customize their QC-related procedures based on, among other things, the firm's structure, procedures performed in prior inspections, past and current inspection observations, the size of the firm, and an assessment of risk related to each focus area. Notably, however, section 104(g)(2) of Sarbanes-Oxley provides that if a quality control criticism or potential defect identified during a PCAOB inspection is addressed by the firm to the Board's satisfaction within 12 months of the date of the Board's inspection report, no portions of the inspection report that deal with that criticism or potential defect will be made public.³²⁵ Making or requiring public disclosure through a publicly available form of QC deficiencies that have been identified during a PCAOB inspection would be inconsistent with this provision of Sarbanes-Oxley, if disclosure were required before the Board has determined whether it is satisfied with the firm's remediation efforts or after the Board has determined that the firm has satisfactorily addressed the deficiencies.

The limitation imposed by section 104(g)(2) is a significant one. In light of section 104(g)(2), it appears that even if the PCAOB were to require Form QC to be publicly available, the PCAOB could not require the disclosure of information regarding the existence or nature of QC deficiencies that are still subject to the Board's remediation determination. However, if information reported by a firm on Form QC informs a QC criticism contained within an inspection report, and if that QC criticism is not addressed to the Board's satisfaction within 12 months of the date of that report, then the QC criticism would be made public in accordance with section 104(g)(2).

The Board believes that the omission of deficiencies that are still subject to the Board's remediation determination (or as to which the Board has made a favorable remediation determination) would result in a publicly available Form QC that supplies an incomplete and potentially misleading picture of the effectiveness of the firm's QC system. This view is guided by the familiar principle that omitting material facts from a disclosure can cause the

statements that are made to be misleading.³²⁶ The Board's decision not to mandate public disclosure of Form QC, in a context where material information (namely, the existence and nature of QC deficiencies that are still subject to the Board's remediation determination) may often be omitted, is motivated in part by that concern, not by any lack of confidence in investors' ability to interpret the information provided to them. For example, a firm may have self-identified a number of relatively minor QC deficiencies in its own evaluation, while QC deficiencies identified by the PCAOB are more severe or could be of greater public interest. In a partial disclosure scenario, the firm would disclose the minor matters, but not the more significant ones that are still subject to the Board's remediation determination, creating a misleading picture of the state of its QC system.

The Board was also concerned that, in certain circumstances, even such partial disclosure would conflict with section 104(g)(2) of Sarbanes-Oxley. For example, assume firms were required to disclose the conclusion of their most recent evaluation and any QC deficiencies that were self-identified, but not any PCAOB-identified QC deficiencies that remain subject to the Board's remediation determination. Under such an approach, if a firm had PCAOB-identified QC deficiencies but no additional self-identified QC deficiencies, then the firm would not disclose any specific QC deficiencies but would disclose an overall conclusion (either "effective except for one or more QC deficiencies that are not major QC deficiencies" or "ineffective," depending on the nature of the PCAOB-identified deficiencies) that nonetheless reveals that the firm has unremediated QC deficiencies, without specifically identifying them. In such a scenario, the Board would be indirectly requiring firms to disclose the existence of PCAOB-identified QC deficiencies that are still subject to the Board's remediation determination, notwithstanding section 104(g)(2) of Sarbanes-Oxley.

Moreover, public disclosure of portions of Form QC may in some cases be subject to other legal constraints imposed by Sarbanes-Oxley. Depending on how a QC deficiency has come to light, certain information contained within a Form QC might be confidential pursuant to section 105(b)(5)(A) of Sarbanes-Oxley, which addresses documents and information prepared or received by or specifically for the Board

³²⁴ See QC 1000.71b.

³²⁵ See section 104(g)(2) of Sarbanes-Oxley, 15 U.S.C. 7214(g)(2); see also PCAOB Rule 4009.

³²⁶ See, e.g., 17 CFR 240.10b-5(b).

in connection with an inspection or investigation.³²⁷ Additionally, Form QC requires firms to report on remedial actions that in certain (though likely rare) circumstances may be subject to laws relating to the confidentiality of proprietary, personal, or other information, or might reasonably be identified by a firm as proprietary. In such a scenario, the Board, in accordance with section 102(e) of Sarbanes-Oxley, would need to honor a firm's properly substantiated request for confidential treatment of such information.³²⁸

The Board also believes that firms may be in a better position to report fully and candidly to the PCAOB about their annual evaluation—more effectively supporting both their own remediation efforts and PCAOB oversight activities—if they are confident that the information would be understood and used in the context of a broader understanding of their overall audit practice and an ongoing dialogue between the firm and the PCAOB.

Accordingly, the Board adopted Form QC as a nonpublic form, as proposed.

To that end, the Board adopted new PCAOB Rule 2203A, which establishes the Form QC reporting requirement and specifies that the Board will not make a filed Form QC or the contents thereof (including any amendment thereto) public.³²⁹ The rule does not, however, prohibit a firm from voluntarily disclosing its Form QC or the contents thereof to the public or to particular stakeholders. Nor does the rule prohibit the PCAOB from sharing Form QCs or their contents and related documentation with the SEC or other entities, consistent with Sarbanes-

Oxley.³³⁰ The rule expressly provides that Form QCs and their contents may be publicly disclosed in enforcement proceedings.³³¹

One commenter noted that Form QC or its contents may not be relevant to all enforcement proceedings and suggested that the Board explicitly clarify in the final standard that the Form QC may become public as part of an enforcement proceeding where Form QC or its content is relevant to the respective enforcement proceeding. The Board does not believe that such a clarification is necessary. When a Form QC or its content is relevant to an enforcement proceeding, it would be admissible, and when it is not relevant to an enforcement proceeding, PCAOB adjudication rules already specify that it shall be excluded.³³²

The rule also provides that the Board may publish Form QC information in summaries, compilations, or other general reports, provided that the firm or firms to which particular Form QC information relates are not identified (unless the information has previously been made public by the firm or firms involved or by other lawful means). Two commenters suggested that the Board could publish Form QC information in summaries, compilations, or other general reports, provided that the firms are not identified. However, another commenter did not support aggregated anonymized information and suggested that this would depart from the spirit and letter of the confidentiality provisions of Sarbanes-Oxley. The Board believes that summaries, compilations, or general reports that present relevant QC-related information on an aggregated and anonymized basis may provide useful insight to investors, audit committees, firms, and other stakeholders about firm QC systems, the implementation of QC 1000, and related matters. The Board also continues to believe that presenting such data on an aggregated and anonymized basis would not run afoul of any limitations of Sarbanes-Oxley.³³³

³²⁷ See section 105(b)(5)(A) of Sarbanes-Oxley, 15 U.S.C. 7215(b)(5)(A).

³²⁸ See section 102(e) of Sarbanes-Oxley, 15 U.S.C. 7212(e); PCAOB Rule 2300(b).

³²⁹ Sections 102(b)(2) and (d) of Sarbanes-Oxley authorize the Board to adopt rules requiring firms to periodically update the information contained in their registration applications or provide to the Board information as necessary or appropriate in the public interest or for the protection of investors. See section 102(b)(2)(D), (b)(2)(H), and (d) of Sarbanes-Oxley, 15 U.S.C. 7212(b)(2)(D), (b)(2)(H), and (d). section 102(e) of Sarbanes-Oxley, in turn, permits the Board to designate in its rules the portions of registration applications and annual reports that will be made available for public inspection (subject to applicable laws relating to the confidentiality of proprietary, personal, or other information, and provided that the Board shall protect from public disclosure information reasonably identified by the firm as proprietary information). See section 102(e) of Sarbanes-Oxley, 15 U.S.C. 7212(e); see also PCAOB Rule 2300(a)(2) (providing that forms filed pursuant to Part 1 or Part 2 of Section 2 of the Board's rules will be publicly available "except to the extent otherwise specified in the Board's rules or the instructions to the form").

³³⁰ See, e.g., section 105(b)(5)(B) of Sarbanes-Oxley, 15 U.S.C. 7215(b)(5)(B).

³³¹ On Form QC, firms may elect to request notification from the Board if the Board is requested by legal subpoena or other legal process to disclose information contained in Form QC. The Board will make reasonable efforts to honor such a request. This notification process does not apply to the PCAOB's or the SEC's use of Form QC or its contents in an enforcement proceeding, because those scenarios do not involve Board disclosure of Form QC information in response to a legal subpoena or other legal process.

³³² See PCAOB Rule 5441, Evidence: Admissibility.

³³³ For comparison, see PCAOB Rule 4010, *Board Public Reports*, which provides, in pertinent part, that the Board may publish summaries,

While firm reporting on Form QC will be nonpublic due to the aforementioned legal constraints and policy considerations, the Board notes that other aspects of QC 1000 and related requirements promote transparency about firm QC systems within the confines of those constraints. For example, the PCAOB has observed the emerging practice of firm transparency reporting, including that the nature and content of these reports continues to evolve and expand in response to market demand. Advances in thinking about firm and engagement metrics could also affect what financial statement users demand and what firms could usefully provide. QC 1000 requires that the QC system operate over any public reporting that firms do provide, including any public reporting of metrics. Firms have to establish a specific quality objective with regard to their public reporting, including that any firm-level or engagement-level information with respect to the firm's audit practice, firm personnel, or engagements communicated to external parties be accurate and not misleading, and—as with any quality objective—they have to monitor their performance in relation to that objective and remediate identified deficiencies.

As part of their annual reporting on Form 2, all registered firms will also be required to provide an annual confirmation with regard to the design of their QC system under QC 1000 and whether they were required to implement and operate the QC system. The Board believes an annual confirmation will be a useful reminder to all firms of their responsibilities regarding the design, implementation, and operation of an effective QC system. The Board also believes that the public will benefit from being able to determine whether a particular firm has been required to implement and operate its QC system from year to year. Such information on Form 2 will be publicly available on the PCAOB website and will be accessible to investors and other financial statement users, audit committees, and other stakeholders. It will also inform PCAOB oversight efforts.

To accompany the changes to Form 2, a similar confirmation has been added to the application for PCAOB

compilations, or other general reports concerning the findings and results of its inspections, including discussion of QC criticisms or potential QC defects, provided that no such published report shall identify the firm or firms to which such criticisms relate, or at which such defects were found, unless that information has previously been made public in accordance with PCAOB Rule 4009, by the firm or firms involved, or by other lawful means.

registration, Form 1. The Board believes such a confirmation will appropriately put applicants on notice of their obligations with respect to their QC systems, which would apply from and after the time that their registration is approved.

iii. Certification of the Evaluation of the Firm's QC System by Firm Leadership

As proposed, the Board required that both the individual assigned ultimate responsibility and accountability for the QC system as a whole and the individual assigned operational responsibility and accountability for the firm's QC system as a whole (the "QC certifiers") certify the firm's report to the PCAOB on the evaluation of its QC system.³³⁴ Several commenters were supportive of the certification requirement, including a commenter that stated that individual certifications are likely to focus the mind and it seems likely that improvements will be seen as a result of such a requirement.

Some commenters opposed the certification requirement, saying it adds little value to the evaluation of the QC system, may not provide a full view of the subject matter it purports to be certifying to and may create an unjust reliance by a third party on the certification, or is an ineffective incentive for making quality control a higher priority within a firm. Another suggested that while certification may sharpen an individual's sense of accountability, this may not necessarily lead to and cannot guarantee enhanced engagement quality. Another commenter suggested that certification requirements could act as a barrier to registration for firms operating in environments in which there are no Sarbanes-Oxley style reporting requirements,³³⁵ and that it could have

a disproportionate impact on smaller firms.

The Board continues to believe that, analogous to the CEO and CFO certifications required under Sarbanes-Oxley, certification of Form QC will lead to increased discipline in the evaluation process and will reinforce the accountability of the certifying individuals, which in turn should improve the quality of the firm's evaluation. The text of the certification, which is unchanged from the proposal, appears in Item 3.2 of Form QC. That item requires certification of certain information regarding the design and evaluation of a firm's QC system, including that each QC certifier reviewed the Form QC and that the disclosures made in the Form QC are complete and accurate in all material respects to the individual's knowledge.³³⁶

As proposed, the final rules require certification from both the individual assigned ultimate responsibility and accountability for the QC system (*i.e.*, the firm's principal executive officer(s)) and the individual assigned operational responsibility and accountability for the QC system. One commenter suggested that certification be required only from the individual with ultimate responsibility and accountability for the firm's QC system on the basis that, in the event of differences of opinion between the two certifiers, the individual responsible for the operational responsibility and accountability for the QC system could be subject to excessive pressure from the firm's principal executive officer. However, under EI 1000, certifiers will be subject to a duty to act with integrity, which includes not subordinating their professional judgment, and the individual with ultimate responsibility and accountability for the firm's QC system will have a number of obligations (for example, under QC 1000.14a.) that are inconsistent with the exercise of undue influence over a subordinate.

The Board does not require similar certifications from other personnel in the QC system, but firms may choose to institute policies that require levels of certification internal to the firm to assist those certifying Form QC.

Some commenters raised concerns about the potential liability of the QC certifiers. Several requested clarification on whether the QC certifiers could be held personally liable for an inaccurate statement only if they made the statement knowing it was false or recklessly not knowing it was false. One of these commenters further stated it had concerns about the potential for unnecessary and excessive liability that the certification could impose upon the QC certifiers, and the effect that this could have on firms' ability to recruit qualified professionals to serve. The commenter further suggested that the final adopting release expressly state that while the QC certifiers are responsible for exercising professional competence in connection with the design and operation of the firm's QC system (and may face consequences for failure to do so), the QC certifiers shall not be held responsible for inevitable system errors or the wrongful acts of others which may, in limited circumstances, overcome the best of those efforts.

If a QC certifier fails to certify the firm's Form QC, such conduct would constitute a violation of the individual's obligation under either paragraph .14d or .15b of QC 1000, as applicable to the particular individual. The Board believes this requirement is important for creating accountability within the firm to achieve the reasonable assurance objective.

Beyond that, QC certifiers' potential liability for statements contained within the Form QC certification is informed by the particular language of those statements. Certain statements in the certification reflect objective facts that the Board believes are readily knowable by the individual. Paragraph 1 of the certification, for instance, recites that the individual reviewed the firm's report on Form QC. Paragraph 3(a) of the certification contains an acknowledgement that the individual is responsible and accountable for the firm's QC system as a whole and has designed, or caused to be designed, the QC system to ensure that it meets QC 1000's reasonable assurance objective. Notably, this paragraph is not tantamount to a certification that the firm's QC system in fact meets QC 1000's reasonable assurance objective; on the contrary, Form QC contemplates that a firm might conclude, and report on its certified Form QC, that its QC

³³⁴ See QC 1000.14d and .15b.

³³⁵ Under SEC rules adopted pursuant to section 302 of Sarbanes-Oxley, CEOs and CFOs of issuers are required to certify, for each quarterly or annual report of the issuer, among other things, that (1) they have reviewed the report; (2) based on the officer's knowledge, the report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made not misleading; (3) based on the officer's knowledge, the financial statements and other financial information included in the report fairly present in all material respects the financial condition and results of operations of the issuer; (4) they (a) are responsible for establishing and maintaining internal control over financial reporting, (b) have designed ICFR to ensure that material information is made known to them, (c) have evaluated the effectiveness of ICFR, and (d) have presented their conclusions about the effectiveness of ICFR in the report; and (5) they have disclosed to the issuer's auditors and audit committee any significant deficiencies in ICFR and any fraud involving management or others involved with ICFR. See 17 CFR 240.13a-14(a), 240.15d14(a).

³³⁶ See *e.g.*, Daniel A. Cohen, Aiysha Dey, and Thomas Z. Lys, *Corporate Governance Reform and Executive Incentive: Implications for Investments and Risk Taking*, 30 Contemporary Accounting Research 1298 (2013) (finding that their sample of firms significantly reduced investments in risky projects in the period following SOX); Hsihui Chang, Jengfang Chen, Woody M. Liao, and Birendra K. Mishra, *CEOs'/CFOs' Swearing by the Numbers: Does it Impact Share Price of the Firm?*, 81 The Accounting Review 22 (2006) (concluding that the SEC order requiring filing of sworn statements by CEOs and CFOs had a positive effect on the market value of certifying firms); Gerald J. Lobo and Jian Zhou, *Did Conservatism in Financial Reporting Increase after the Sarbanes-Oxley Act? Initial Evidence*, 20 Accounting Horizons 57 (2006).

system is not effective. Rather, in paragraph 3(a), the QC certifiers acknowledge their role in designing (or causing to be designed) the firm's QC system. Paragraph 3(b) of the certification states that the individual evaluated the effectiveness of the firm's QC system and has presented in Form QC the conclusions reached. With respect to each of these statements in the Form QC certification, the Board believes that the QC certifiers can and should reach a conclusion about their accuracy through the exercise of due professional care. In light of the nature of these statements, the Board does not agree with the commenters that a showing of recklessness or knowing misconduct is necessary to establish a violation with respect to these aspects of the Form QC certification.

The other statements in the Form QC certification are subject to knowledge qualifiers. In paragraph 2, the QC certifier states that the disclosures made in Part II of Form QC regarding the evaluation of the effectiveness of the firm's system of quality control are complete and accurate in all material respects "[b]ased on my knowledge." Similarly, paragraph 3(c) states that the QC certifier has disclosed, based on the evaluation of the QC system, all unremediated QC deficiencies "of which I am aware." These statements would be inaccurate, and the QC certifier's certification would therefore constitute violative conduct, only if they were knowingly false (if the QC certifier knew that Part II was not complete and accurate in all material respects, or if the QC certifier was aware of undisclosed unremediated QC deficiencies), or if they were made recklessly not knowing they were false.

One commenter suggested that the certification say "to the best of my knowledge" rather than "based on my knowledge," and another commenter suggested that the wording of the certification be updated to "in my capacity as the individual assigned [ultimate/operational] responsibility" rather than "who have been assigned [ultimate/operational] responsibility." After consideration of these comments, the Board believes that the proposed language is clear, appropriate, and likely to be easily understood, and does not believe that the proposed certification text requires amending.

One commenter did not support the clause in the proposed certification that states that the firm has disclosed all unremediated quality control deficiencies. The commenter, while acknowledging that this statement is subject to a knowledge qualifier, suggested that this certification could

lead to unnecessary disputes over what the QC certifiers should have known in a particular circumstance and suggested that obtaining a certification from the firm (not the individual) may sufficiently address this item without discounting the standards to which auditors are held. As discussed above, the inclusion of "of which I am aware" in paragraph 3(c) of certification means that liability would arise with respect to that paragraph only if the QC certifier made the statement knowing it was false or recklessly not knowing it was false.

Another commenter also suggested that the standards clarify that such certification relates to the "firm's evaluation" of its QC system, and not a specific individual's evaluation of the quality management system. As reflected in paragraph .77 of QC 1000, the annual evaluation is conducted by the firm, but the firm, as a legal entity, acts through individuals, and the QC certifiers are the individuals who, under the standard, are responsible and accountable for the QC system as a whole and are required to certify the firm's report to the PCAOB on its annual evaluation.

Another commenter asserted that the text of the certification suggests that a certifying individual should be considered to have violated QC 1000 only to the extent that the inaccuracy in a submitted certification is material to an investor's or reasonable auditor's understanding of the QC system as a whole, and asked that the Board confirm that is the case. The Board does not agree with this characterization of Form QC. Some statements in Form QC, such as the one in paragraph 2, are expressly conditioned on materiality, while other statements, such as that in paragraph 3(b), are not.

One commenter suggested that creating a potential Sarbanes-Oxley type certification for privately held accounting firms and making this available to the public could create market confusion as to what exactly is being certified and the level of reliance users should place on such a certification. The certification does not contain the outcome of the firm's annual evaluation of its QC system or identify any unremediated QC deficiencies, but rather certifies the completeness and accuracy of the information being reported to the PCAOB on Form QC. That information is set forth elsewhere in Form QC and, as explained above, that information is treated as nonpublic. Because the certified information is treated as nonpublic, the Item 3.2 certifications are likewise treated as nonpublic; in the Board's view, the certifications do not present a full or

useful picture of a firm's QC system without the underlying information.

iv. Requirement for Form QC Amendments

The proposed general instructions for Form QC included provisions detailing when amendments of Form QC should be filed. Those instructions indicate that Form QC should be amended only to correct information that was incorrect at the time that the form was filed or to provide information that was omitted from the form and was required to be provided at the time the form was filed. The Board considered commenters' feedback, and retained the language regarding amendments in the proposed general instructions for Form QC, which mirrors the standard for amending certain other PCAOB forms.

Two commenters requested clarification on how firms should consider information that comes to their attention after the evaluation date or the reporting date that is relevant to the firm's conclusion on Form QC, including how this interacts with relevant provisions in proposed EI 1000. Other commenters suggested that revisions to Form QC not be required for inconsequential matters. Other commenters requested guidance on when an amendment to Form QC would be required, and some suggested that a threshold be developed for potential amendments.

QC 1000 requires firms to conduct the annual evaluation of their QC system's effectiveness as of September 30 and to file their report on Form QC regarding that evaluation by November 30. Consequently, annual evaluations under QC 1000 should conclude sometime between October 1 and November 30 of each year. Information that relates to the firm's QC system as of the evaluation date (September 30), and that comes to the firm's attention after the evaluation date but before the firm has filed Form QC, should be factored into the firm's evaluation and reflected, if and as appropriate, in Form QC. In contrast, any information that relates to the firm's QC system as of the evaluation date, but that comes to the firm's attention after the firm has filed its Form QC, would not need to be reflected on Form QC or on an amendment to Form QC (although it may constitute a QC observation to be considered in the next annual evaluation of the QC system).

In other words, Form QC captures, and conveys to the Board, the conclusions reached by the firm as a result of its completed annual evaluation, and that evaluation cannot disregard information that comes to light before Form QC has been filed.

Therefore, when Form QC is filed, it should be complete and accurate as of the date of its filing. Similar to PCAOB staff guidance on Form 2 reporting,³³⁷ if a firm discovers that it provided incorrect information in a filed Form QC or omitted information that should have been included based on information that the firm was aware of at the time of filing, then the firm should file an amended Form QC. That amendment obligation is not subject to any materiality or other thresholds, because the Board believes it is entitled to receive Form QCs that contain information that is correct and that do not omit information that was required to be provided. The Board does not believe that any of the information on Form QC is inconsequential.

v. Reporting to the Audit Committee

In connection with the proposal of QC 1000, the Board also proposed amendments to AS 1301, *Communications with Audit Committees*, which contemplated communication to the audit committee of certain information about the firm's most recent evaluation of its QC system. Several commenters supported the amendments as proposed. Other commenters supported limiting the communications to the conclusion of the annual evaluation or limiting communication of deficiencies to only major QC deficiencies. One commenter expressed concern with reporting to audit committees about all unremediated QC deficiencies that exist as of the evaluation date, in part because of the interaction of such communications with the confidentiality restrictions under section 105(b)(5)(A) of Sarbanes-Oxley. The commenter further suggested that requiring all QC deficiencies to be communicated would create more extensive communication requirements for firms related to QC deficiencies than what auditors are required to communicate to audit committees in an audit of ICFR, and in addition, this approach would differ from management's external reporting on its ICFR to its stakeholders, which solely discloses deficiencies that are material weaknesses.

One commenter asserted that audit committees are likely to find more value in understanding quality matters specific to the engagement and having a broader dialogue about the firm's approach to quality control. Two

commenters argued that a firmwide report on audit quality would have little utility to each individual audit committee. One of these commenters suggested instead that audit committees would be more influenced by an independent verification of the QC system such as the PCAOB inspection report on their auditor, and information relating to the auditor's performance on their engagement, including audit quality indicators. The other commenter recommended that firms report relevant human resource metrics to the audit committee and explain what was done to assure audit quality was not compromised. One commenter asserted it could be extremely challenging for audit committees to understand and reconcile the information that would be communicated to them under the proposed changes to AS 1301, especially given the considerable time period between the issuance of public portions of firm inspection reports and the potential release of nonpublic inspection findings. One commenter did not support the requirement to disclose a firm's QC deficiencies to audit committees, and stated that QC deficiencies may have little to no impact on a given reporting issuer's audit or that area of the firm's practice. Another commenter questioned whether or not the audit committee would be inclined to seek a new auditor based only on a firm-wide evaluation of quality control furnished to the audit committee by the auditor. One commenter was generally supportive of the requirements but expressed concern with the timing of the required communication due to existing important year-end communications. The commenter expressed concern that not communicating QC deficiencies known at a January 15 reporting date could potentially introduce legal considerations that could place tension on the engagement team and the firm's obligation to comply with other existing required communications under AS 1301. One commenter recommended specifying that this communication is not required to be in writing due to confidentiality concerns, and two commenters did not support any required communication of the annual evaluation of the QC system to the audit committee.

One commenter asserted that requiring firms to communicate to audit committees about their most recent annual QC evaluations is inconsistent with the Congressional balance struck in Sarbanes-Oxley section 104(g)(2). In addition, the commenter suggested that the requirement indirectly regulates the

actions of audit committees and imposes a fiduciary duty of care on audit committees, regardless of whether quality control issues relate to the performance of the engagement, which is beyond the scope of the PCAOB's jurisdiction. Another commenter asserted that the proposed communication could also be construed as contradictory to the PCAOB's conclusion that Form QC would be treated as nonpublic.

Several commenters were concerned about the proposed requirement to discuss remedial actions taken and to be taken, and suggested that some of this information may be protected by section 104(g)(2) or section 105(b)(5)(A) of Sarbanes-Oxley. One commenter suggested that the communication of a brief overview of remedial actions taken or to be taken should only be required upon the determination that substantial good faith progress has not been made on the remedial actions.

After consideration of the comments received, the Board determined not to adopt the proposed amendments to AS 1301. Although the Board continues to believe that firms could communicate the overall conclusion of their annual evaluation and their planned remedial actions to audit committees without expressly disclosing information subject to section 104(g)(2) or section 105(b)(5)(A) of Sarbanes-Oxley, the Board recognizes that such a disclosure obligation could present implementation challenges. Specifically, and as discussed in more detail above, there may be challenges associated with compelling firms to publicly disclose certain information about their QC systems while simultaneously preserving their ability not to disclose other related information that may be subject to confidentiality protections, privileges, or prescribed disclosure procedures under Sarbanes-Oxley. The Board believes that the same challenges could arise if firms were compelled to make disclosures to audit committees.

The Board also recognizes that firms and audit committees have direct interaction, so while PCAOB standards do not require firms to make disclosures to audit committees, an audit committee may ask a firm to voluntarily disclose information about its QC system. As the Board has previously noted, such inquiries could include requesting the firm to keep the audit committee apprised of the status of the quality control remediation process (including whether the firm made a submission to the Board responding to inspection report quality control criticisms by the 12-month deadline) and whether the

³³⁷ See *Staff Questions and Answers Annual Reporting on Form 2*, at Q34, available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/registration/rasr/documents/staff_qa-annual-reporting.pdf?sfvrsn=5e7259ff_0.

Board has made a final remediation determination (including a negative determination that has not yet become public).³³⁸

2. Current PCAOB Standards

Current PCAOB QC standards do not require firms to evaluate their QC systems or to report on any such evaluations. As previously noted, some firms conduct evaluations and share their results in published reports, either voluntarily or under other regulatory requirements.

Documentation

Documentation supports a firm's QC system in a number of ways. It helps provide clarity around roles and responsibilities and the firm's policies and procedures, which promotes consistent compliance by firm personnel and other participants. Documentation enables proper monitoring and supports the evaluation and continuous improvement of a firm's QC system. It makes it easier to train firm personnel and other participants and facilitates the retention of organizational knowledge, providing a history of the basis for decisions made by the firm about its QC system. Further, documentation assists others conducting reviews of the firm's QC system by providing evidence of the system's design, implementation, and operation. Current PCAOB standards provide only general direction on the nature and extent of QC documentation and specific requirements for documentation of certain items.³³⁹

Through its oversight activities, the PCAOB has observed that the nature and extent of firms' documentation of their QC systems vary greatly. Some firms have detailed documentation for all areas of their QC systems. Other firms have significantly less documentation. For example, some firms have documentation only in areas that have been subject to PCAOB inspections, such as remediation, root cause analysis, or internal inspections. QC 1000 establishes more comprehensive requirements for firms to document their QC systems.

1. QC 1000

The proposal included an overarching documentation requirement that captured the design, implementation, and operation of the firm's QC system and the annual evaluation of the QC

system. The scope of that requirement was then specified in proposed paragraphs .82 and .83.

The documentation of the design and implementation of the QC system captures decisions made regarding "the who, what, when, where, why, and how" of the QC system. This aspect of documentation will help firm personnel and others understand what is expected of them in fulfilling their responsibilities and support consistent implementation and operation of the firm's QC system. For example, documentation of the design of policies and procedures regarding general and specific independence matters would enable a consistent understanding by firm personnel and others about who is responsible for what, when the responsibilities are triggered, and why certain actions are necessary.³⁴⁰ Such documentation will allow for consistent actions by firm personnel and others in implementing the design of those policies.

The documentation of the operation of the firm's QC system enables the firm to determine if the policies and procedures were operated in the manner that the firm intended.³⁴¹ It would also provide evidence of compliance with the specified quality responses and other requirements of QC 1000. For example, it would provide evidence of how the firm complied with specific communication requirements related to the operation of the firm's QC system and the performance of its engagements³⁴² and whether the quality responses implemented by the firm operated as designed.

The Board received no comments on the general obligation to prepare and retain documentation regarding the QC system and paragraph .81 was adopted as proposed. The comments received regarding the scope of the proposed documentation requirement are addressed below, in connection with the discussion of paragraphs .82 and .83.

The proposal included a list of specific matters that firms would be required to document. Documentation of the lines of responsibilities and supervision within the QC system should reduce operational ambiguity and provide clarity about who within the firm is accountable for various firm supervisory responsibilities within the firm's QC system. One firm suggested that the phrase "successive senior levels" may not be clear. As discussed

in more detail above, under QC 1000.27, the firm should establish and maintain clear lines of responsibility and supervision—including defining authorities, responsibilities, accountabilities, and supervisory and reporting lines for roles within the firm, up to and including the principal executive officer(s)—within the QC environment. A description of these successive lines of responsibility and supervision must be included in the documentation of the QC system, and a reference to paragraph .27 was added to clarify that point.

The requirement for the firm to document aspects of its risk assessment process ensures that the firm will have adequate evidence to support its annual risk assessment. Specifically, the firm is required to document identified quality risks, reasons these risks were identified, and policies and procedures the firm had put in place in response. This documentation is valuable in subsequent risk assessments and could help to support decisions about, for example, whether to establish additional quality objectives, identify new or modified quality risks, or design and implement new quality responses.

The requirements for the firm to document aspects of its monitoring and remediation process will also support its monitoring and remediation activities. For example, a firm's documentation of engagement and QC system-level monitoring activities performed, its evaluation of the results of those monitoring activities, actions taken to address engagement deficiencies, and identified QC deficiencies would demonstrate the firm's approach to complying with certain requirements of the standard for the monitoring and remediation process component. This documentation will also assist the firm in monitoring its monitoring and remediation process and in making its annual evaluation of the effectiveness of the QC system pursuant to paragraph .77.

The standard also requires the firm to document the basis for the conclusion it reached in evaluating the effectiveness of its QC system pursuant to paragraph .77. This documentation provides evidence of the decisions made in reaching the conclusion about the effectiveness of the firm's QC system, which may be valuable in future evaluations and in establishing compliance with the firm's reporting obligations to the PCAOB.

The standard requires the firm to document certain matters if the firm uses resources or services provided by a network or a third-party provider in the firm's QC system or the performance

³³⁸ See *Information for Audit Committees about the PCAOB Inspection Process*, PCAOB Rel. No. 2012-003, at 11 (Aug. 1, 2012), available at https://pcaobus.org/Inspections/Documents/Inspection_Information_for_Audit_Committees.pdf.

³³⁹ See, e.g., QC 20.21, .24–.25.

³⁴⁰ See, e.g., QC 1000.33–.34.

³⁴¹ Firms that are not required to implement and operate their QC system would not be expected to have anything to document with respect to the operation of the QC system.

³⁴² See, e.g., QC 1000.55–.57.

of the firm's engagements. When a firm uses resources or services provided by a network or a third-party provider, the standard requires the firm to document how the resources or services are developed and maintained and, if such services or resources were supplemented or adapted, how and why they were supplemented or adapted. Firms will also have to document how the resources or services were implemented and operated. Documentation of such matters will serve as evidence of decisions made regarding resources or services used by the firm.

Some networks or third-party providers may provide documentation about their services or resources to the firm. For example, the firm may obtain an understanding of how the resources were developed and maintained by the network through documentation provided by the network. This documentation may need to be supplemented by the firm depending on various factors, including the extent of the documentation provided and whether the firm supplements or adapts the resource or service.

As discussed above, a reference to paragraph .27 was added to paragraph .82a. to clarify that a description of the successive lines of responsibility and supervision must be included in the documentation of the QC system. Paragraph .82 was otherwise adopted as proposed.

Requiring documentation to be in sufficient detail to support a consistent understanding of the QC system by firm personnel, including an understanding of their roles and responsibilities with respect to the firm's QC system, will help to clarify the firm's expectations of its personnel and promote consistent compliance with the firm's QC policies and procedures.

One firm expressed concern that this "consistent understanding" threshold may not be easily understood. The Board believes that firms will be able to determine the nature and extent of the documentation needed to facilitate a consistent understanding by firm personnel based on the functioning of their QC system. Based on the requirements in paragraph .83a, firms would initially determine the appropriate level of detail of documentation based on the experience they already have in implementing and operating a QC system under current standards and whether their personnel understand their roles and responsibilities, and modify documentation as needed over time based on their monitoring and

remediation activities and the results of their QC system evaluations.

As described previously, documentation supports a firm's QC system in a number of ways. For example, it provides clarity around the firm's policies and procedures, enables proper monitoring, and supports the evaluation and continuous improvement of a firm's QC system. Documentation also facilitates the retention of organizational knowledge, providing a history of the basis for decisions made by the firm about its QC system. Further, it assists others conducting reviews of the firm's QC system by providing evidence of the system's design, implementation, and operation.

In particular, the Board believes that appropriate documentation of the QC system is necessary for the PCAOB to fulfill its statutory mandate to protect investors and the public interest. Sarbanes-Oxley requires that, in conducting an inspection of a registered public accounting firm, the PCAOB evaluates the sufficiency of the quality control system of the firm and the manner of the documentation and communication of that system by the firm.³⁴³ Sarbanes-Oxley further authorizes the PCAOB to perform such other testing of quality control procedures as are necessary or appropriate in light of the purpose of the inspection and the responsibilities of the Board.³⁴⁴ In addition, the Board's rules provide that a regular inspection will include, but is not limited to, the steps and procedures as specified in sections 104(d)(1) and (2) of Sarbanes-Oxley and any other tests of the audit, supervisory, and quality control procedures of the firm as the Director of the Division of Registration and Inspections or the Board determines appropriate.³⁴⁵ As part of the Board's inspection procedures, firms will be expected to provide the PCAOB with evidence relating to the effectiveness of the QC system.

Given that mandate, the level of documentation that would be sufficient to enable PCAOB inspectors to evaluate the effectiveness of a firm's QC system through an inspection may be different from the level of documentation that would be sufficient for the firm to support its annual evaluation. Under QC 1000, a firm must evaluate the effectiveness of its QC system based on the results of its monitoring and

remediation activities,³⁴⁶ and firms can determine the nature, timing, and extent of QC system-level monitoring activities taking into account a number of factors.³⁴⁷ There could be certain quality responses, or certain instances of the operation of quality responses, that are not monitored by the firm within a given year and not considered in connection with the firm's annual evaluation. If the firm were required to prepare and retain documentation only to the extent related to its own annual evaluation, the firm might not prepare and retain documentation to evidence that these quality responses operated effectively. However, in light of the scope of the PCAOB's statutory mandate, its inspection procedures cannot be limited to quality responses (and, to the extent applicable, samples of the operation of quality responses) that the firm chose to monitor in the period. On the contrary, firms will be expected to provide evidence of the operating effectiveness of any quality responses selected for inspection in connection with the PCAOB's evaluation of the effectiveness of the firm's QC system.

Therefore, the proposed standard contemplated that, in order to effectively support the firm's QC system, the documentation of the QC system needs to be at the level of detail to enable an experienced auditor that understands QC systems but has no experience with the design, implementation, and operation of the firm's QC system to understand the design, implementation, and operation of the QC system, including the quality objectives, quality risks, quality responses, monitoring activities, remedial actions, and basis for the firm's conclusions reached in the evaluation of the QC system ("experienced auditor threshold"). Incorporating the experienced auditor threshold when describing the extent of detail firms are required to document and maintain regarding their QC system is appropriate because that level of detail will facilitate the firm's monitoring activities and external monitoring, including PCAOB inspections conducted in accordance with Sarbanes-Oxley. Two firms agreed that the experienced auditor threshold was appropriate.

Several commenters, including firms and a related group, argued that the proposed documentation requirements were too broad, and suggested a variety of different limitations to narrow their scope. Some firms suggested that the standard differentiate data relating to

³⁴³ See section 104(d)(2) of Sarbanes-Oxley, 15 U.S.C. 7214(d)(2).

³⁴⁴ See section 104(d)(3) of Sarbanes-Oxley, 15 U.S.C. 7214(d)(3); see also Rule 4001, *Regular Inspections*.

³⁴⁵ See Rule 4001, *Regular Inspections*.

³⁴⁶ See QC 1000.77.

³⁴⁷ See QC 1000.65.

the operation of the QC system from data relating to the design, implementation, and annual evaluation of the QC system, with a shorter retention period for the former. Other commenters, including firms and a related group, recommended that the documentation requirements be comparable to the documentation requirements that Sarbanes-Oxley imposes on issuers with regard to management's assessment of the effectiveness of the issuer's internal control over financial reporting.³⁴⁸ Another firm suggested that the documentation requirements be comparable and analogous to the documentation retention requirements set out in the SEC's rules for issuer audits and related interpretive guidance.³⁴⁹ One firm and a related group suggested that the documentation requirements be limited to the evidence to support the annual evaluation of the QC system and related monitoring. Two firms suggested that additional guidance or clarity would be necessary in order for firms to appropriately adopt documentation retention policies related to the operation of controls that meet the expectations of the proposed standard.

The Board does not believe that any of the more narrowly scoped documentation requirements suggested by commenters would be appropriate. QC 1000's documentation requirements need to be aligned with the PCAOB's mandate, provided by Congress, to "evaluate the sufficiency of the quality control system of a firm" through its inspection procedures.³⁵⁰ Therefore, the Board believes that it is imperative that documentation that enables the experienced auditor to evaluate the operation of the quality responses should be included in the documentation that is prepared and retained by the firm.

To clarify the level of detail of the documentation relating to the operation of the QC system that is to be prepared and retained under QC 1000, paragraph

.83 was revised to include a note to .83b. stating that with respect to the operation of the QC system, the documentation must include documentation that enables the experienced auditor to evaluate the operation of the quality responses. As discussed in connection with paragraph .86 below, the Board continues to believe that all of the documentation required under the standard should be retained for seven years.

Commenters also expressed concern that firms would be required to retain large volumes of documentation. Several commenters suggested that the costs associated with retaining documentation of the operation of the QC system would be burdensome, and some further commented that the data relating to the operation of the QC system could include sensitive data, and a requirement to prepare and retain all such data could also introduce heightened data security risks. One firm suggested the Board consider adding language that appears in SQMS 1 clarifying which matters require documentation, specifically referencing SQMS 1 paragraphs A224 and A227.³⁵¹

In considering commenters' concerns that the documentation to support that the quality responses operated effectively in every instance would result in a substantial volume of documentation, the Board believes that the ability to effectively monitor whether the firm's quality responses are properly designed and operating effectively should not be restricted by the documentation requirements of the standard. Furthermore, the Board believes that the new note to paragraph .83b clarifies that the firm need not prepare and retain excessively voluminous documentation of the day-to-day operation of every action of its QC system, provided the information is not required to satisfy the requirements of paragraphs .82–.83.

³⁵¹ Paragraph A224 of SQMS 1 states that it is neither necessary nor practicable for the firm to document every matter considered, or judgment made, about its system of quality management. Furthermore, compliance with this SQMS may be evidenced by the firm through its information and communication component, documents or other written materials, or IT applications that are integral to the components of the system of quality management. Paragraph A227 of SQMS 1 states that the firm is not required to document the consideration of every condition, event, circumstance, action, or inaction for each quality objective or each risk that may give rise to a quality risk. However, in documenting the quality risks and how the firm's responses address the quality risks, the firm may document the reasons for the assessment given to the quality risks (that is, the considered occurrence and effect on the achievement of one or more quality objectives) to support the consistent implementation and operation of the responses.

The Board believes that the extent of documentation sufficient to evidence whether the quality responses operated effectively would scale with the size of the firm's PCAOB practice and the risks and complexities of their engagements and, in turn, the assessed quality risks and the quality responses established to address them. Therefore, the documentation requirements of the standard should be less costly and burdensome for firms with smaller PCAOB audit practices, which the Board believes is appropriate.

In addition, firms are able to evaluate the nature and extent of the documentation that is necessary to evidence the operation of the quality responses. In determining the sufficiency of the detail and extent of the QC documentation, the firm may identify quality responses for which the evidence required to be able to demonstrate that the quality response operated effectively may not entail retention of all the information produced in the day-to-day operation of the QC system. For example, in the event that a large volume of automated emails sent by the firm to its employees are evidence supporting that a quality response operated, the firm could evaluate whether alternative evidence (such as email delivery reports or other aggregated data) would provide sufficient support regarding the operation of the quality response—without having to prepare and retain all of the individual emails within the QC documentation. In addition, to the extent that the operation of the firm's QC system includes sensitive data, the firm has flexibility to not include the sensitive data fields in the documentation that is prepared and retained to the extent that they are not necessary to evidence that the quality response operated effectively. Furthermore, informed by its oversight activities, the PCAOB has observed that firms currently archive and retain documentation for extended periods of time and are able to implement processes to appropriately safeguard the information. The PCAOB has also observed instances where firms have migrated systems and still maintained the appropriate documentation through archives or through migration of the information onto the new systems.

As the note to paragraph .83b makes clear, documentation of every aspect of the operation of the firm's QC system may not be required to evidence that each quality response operated effectively. For example, there may be certain documentation, such as emails or meeting invitations that are sent as part of the day-to-day operation of the

³⁴⁸ See 17 CFR 229.308 (requiring issuers to maintain evidential matter, including documentation, to provide reasonable support for management's assessment of the effectiveness of ICFR).

³⁴⁹ See 17 CFR 210.2–06(a) (requiring, for audits or reviews of an issuer's financial statements, retention of records relevant to the audit or review, including workpapers and other documents that form the basis of the audit or review, and memoranda, correspondence, communications, other documents, and records (including electronic records), which: (1) Are created, sent or received in connection with the audit or review, and (2) Contain conclusions, opinions, analyses, or financial data related to the audit or review).

³⁵⁰ See section 104(d)(2) of Sarbanes-Oxley, 15 U.S.C. 7214(d)(2).

QC system, that may not be necessary to enable an experienced auditor to evaluate the effective operation of the quality responses. In these circumstances, the firm may determine it is not required to prepare and retain this information within the documentation of its QC system. However, the Board also believes that there may be circumstances in which an email or meeting invitation needs to be retained because it evidences how a quality response operated to address a quality risk and is necessary to enable an experienced auditor to evaluate the operation of the quality response.

Although some commenters suggested the documentation requirements be analogous to the SEC's ICFR documentation retention guidance, the Board does not believe that is an appropriate threshold. The SEC's guidance indicates that management's documentation needs to provide "reasonable support" for its ICFR assessment and that management's documentation need not include all controls that exist within a process that impacts financial reporting, but should be focused on those controls that management concludes are adequate to address the financial reporting risks.³⁵² QC 1000 is not a "reasonable support" standard and instead requires documentation to understand how the firm's quality responses are designed to address the quality risks and evidence the operation of the QC system.

The standard's approach to documentation requirements is principles-based and provides for scalability. When determining the form, content, and extent of documentation, the firm will consider, among other things, the nature and circumstances of the firm and the nature and complexity of the matter being documented. For example, for a large multi-office firm that performs many audits under PCAOB standards, the extent of documentation would be greater than for a small, single-office firm with a few firm personnel that audits one issuer or broker-dealer. The firm's documentation may take the form of formal written manuals and checklists or may be informally documented (e.g., in email communications), subject to the requirement of paragraph .83 that the documentation be in sufficient detail to support a consistent understanding of the QC system by firm personnel and for an experienced auditor to understand

the design, implementation, and operation of the QC system. The firm may determine that a detailed memo is a more appropriate form of documentation for more complex matters, whereas, for less complex matters, briefer communications, such as email, may suffice. The nature and circumstances of the firm and the nature and complexity of the matter being documented are not the only factors that could drive the form, content, and extent of documentation. There may be other factors, such as the nature of the firm's engagements or the frequency and extent of changes in the firm's QC systems. The Board believes this principles-based approach provides for scalability and that providing specific guidelines and detailed examples of various types of documentation would potentially limit firms' flexibility unnecessarily.

The proposal contemplated that firms would have to concurrently file their Form QC and assemble their documentation for retention by the same date. As adopted, the standard provides that firms have an additional 14 days after the date that the firm is required to file Form QC to assemble their documentation. Several commenters expressed concern with having the QC documentation completion date be concurrent with the date that the firm must report annually to the PCAOB on Form QC pursuant to paragraph .79. Many of these commenters recommended a document completion date 45 days after the reporting date, with some of these commenters suggesting that 45 days would ensure consistency with the requirements of AS 1215. One firm suggested that a full 45 days to assemble a complete and final set of documentation was not necessary, but the time period needed to assemble documentation should be built into an evaluation of the length of the reporting period if the final standard retained a document completion date concurrent to the reporting date.

After consideration of the comments received, the Board revised paragraph .84 to provide firms up until December 14 (a total of 75 days after the evaluation date) to complete a final set of QC documentation. This includes an additional 14 days after the date that the firm is required to report to the PCAOB on Form QC. The 14-day period aligns with the changes to PCAOB requirements for engagement documentation.³⁵³ The Board believes

that larger PCAOB audit practices with more complex and scaled up QC systems will employ the use of electronic tools in the assembly of the documentation of the QC system, and therefore a 14-day period to the QC documentation completion date is feasible. In addition, for smaller PCAOB audit practices with scaled down QC systems, the Board expects that the volume of documentation to be assembled will be smaller such that a 14-day period is also feasible for those firms. Furthermore, the Board notes that, because the final rule includes a longer period from evaluation date to reporting date than proposed, under the final standard firms will have 75 days after the evaluation date to assemble their documentation, rather than 45 days as proposed.

The standard permits additional documentation supporting a firm's QC system to be added after the QC documentation completion date in a manner similar to the addition of audit evidence to audit documentation under AS 1215.16. When this occurs, the standard requires a firm to indicate the date the information was added, the name of the person who prepared the additional documentation, and the reason for adding it. The standard also requires all previously retained documentation supporting the firm's evaluation of its QC system to remain intact and not be discarded.

The proposed standard contemplated that the firm would retain QC documentation for seven years from the QC documentation completion date, unless a longer period is required by law.

Two firms commented that they believed the seven-year retention period to be cost-prohibitive. One of these firms commented that if the firm changed its systems, for example, it will have to maintain additional licenses for old systems to access and use the data and pay for up to seven years' worth of storage, and it believes that maintaining that much data would introduce unnecessary cost as well as increased cybersecurity risk. The firm also commented that the seven-year retention period goes beyond the retention requirements of the quality management standards set forth by the

³⁵² See Commission Guidance Regarding Management's Report on Internal Control Over Financial Reporting Under section 13(a) or 15(d) of the Securities Exchange Act of 1934, SEC Rel. No. 33-8810 (June 27, 2007), available at <https://www.sec.gov/files/rules/interp/2007/33-8810.pdf>.

³⁵³ Amendments to the engagement documentation requirements in AS 1215 are addressed in a separate release. See Auditor Responsibilities Release.

AICPA³⁵⁴ and IAASB,³⁵⁵ and that this difference could cause operational challenges. The firm recommended aligning the documentation requirements with the firm's inspection and remediation cycle or allowing the firm to use a risk-based approach based on its judgment. Two firms opposed the seven-year period and suggested that it be based on the most recent inspection (for example, one year from the most recent inspection period), or until the inspection for a particular period has been completed.

As discussed in the proposal, the Board was concerned that requiring the retention period to be aligned with the PCAOB inspection cycle would be too short. A firm's remediation activities may span multiple years and the actions taken by the firm in certain areas may be informed by prior actions. Further, the objective of the documentation requirement is much broader than providing evidence for inspection purposes or enabling proper remediation. As described in the proposal, the Board believes that the documentation may also be useful for training purposes, ensuring the retention of organizational knowledge, and providing a history of the basis for decisions made by the firm about its QC system. One firm commented on these purposes and suggested that firms should determine what documentation has continuing relevance based on the circumstances. Another firm suggested that this could be reasonably handled by firms on a case-by-case basis, and any necessary documentation that could impact or inform future periods could be specifically retained. The firm further commented that some information would become stale over time and that it does not anticipate information retained early on being used for training or the retention of organizational knowledge in later years. A firm and a related group commented that a seven-year retention requirement is appropriate as it pertains to documentation that supports a firm's evaluation of its system of quality control and the related testing.

³⁵⁴ SQMS 1 requires the firm to establish a period of time for the retention of documentation for the system of quality management that is sufficient to enable the firm and its peer reviewer to monitor the design, implementation, and operation of the firm's system of quality management or for a longer period if required by law or regulation. See paragraph 61. Of SQMS 1.

³⁵⁵ ISQM 1 requires the firm to establish a period of time for the retention of documentation for the system of quality management that is sufficient to enable the firm to monitor the design, implementation and operation of the firm's system of quality management, or for a longer period if required by law or regulation. See paragraph 60. of ISQM 1.

After consideration of the comments received, together with the amendment made to paragraph .83. of the standard, the Board adopted the requirement to retain documentation for seven years from the QC documentation completion date, unless a longer period of time is required by law, as proposed. Paragraph .86 was amended to clarify that the documentation to be retained for this period is the documentation of its QC system required under paragraphs .81–.83 and paragraph .85. This requirement aligns the QC document retention requirement with other requirements in PCAOB standards and SEC rules (such as 17 CFR 210.2–06). Furthermore, the documentation relating to the firm's engagements must be retained for seven years,³⁵⁶ and the Board believes that it is appropriate for the firm to also retain documentation of the QC system that operated over those engagements for the same time period. For consistency and practical application, the retention period is the same for all firms and applies to all documentation the firm is required to accumulate to meet the documentation requirements of the standard.

2. Current PCAOB Standards

Existing QC 20 provides that:

- Appropriate consideration should be given to the extent to which QC policies and procedures, and compliance with them, should be documented.³⁵⁷
- The form, content, and extent of documentation depends on relevant factors, including the size, structure, and nature of the firm's practice.³⁵⁸
- A firm should prepare appropriate documentation to demonstrate compliance with its policies and procedures for the QC system.³⁵⁹
- Documentation should be retained for a period sufficient to enable those performing monitoring procedures and a peer review to evaluate the extent of the firm's compliance with its QC policies and procedures.³⁶⁰

QC 30 and the SECPS membership requirements include documentation requirements for certain items such as findings from certain monitoring activities, CPE, notification of cessation of client relationships, filing reviews under Appendix K, and corrective actions to address apparent independence violations.³⁶¹

³⁵⁶ See AS 1215.14.

³⁵⁷ See QC 20.21.

³⁵⁸ See QC 20.24–.25.

³⁵⁹ See QC 20.25.

³⁶⁰ See QC 20.25.

³⁶¹ See, e.g., QC 30.08; SECPS 1000.08(m), 1000.45, 1000.46, 8000.

Additional Amendments

QC 1000 supersedes the existing PCAOB interim QC standards in their entirety. Currently, Rule 3400T requires registered firms and their associated persons to comply with the AICPA's quality control standards as in existence on April 16, 2003, to the extent not superseded or amended by the Board. Rule 3400T identifies the AICPA's Statements on QC Standards (QC 20, QC 30, QC 40) and certain of the AICPA's SECPS membership requirements, which are applicable only to firms that were members of the AICPA SEC Practice Section on April 16, 2003. The Board rescinded Rule 3400T. In consequence, the interim quality control standards referenced in Rule 3400T are no longer part of PCAOB standards. Rule 3400T is replaced with Rule 3400, which describes the auditor's responsibilities for complying with quality control standards adopted by the Board and approved by the SEC.

Other amendments to PCAOB standards, rules, and forms are described below.

Amendments to AS 2901, Consideration of Omitted Procedures After the Report Date, and Related Amendments

1. Background

Currently, AS 2901 applies when the auditor concludes, after issuing its report on the financial statements, that procedures “considered necessary at the time of the audit in the circumstances then existing” were omitted from an audit of the financial statements, but there is no indication that the financial statements are not fairly presented.³⁶² Existing AS 2901 requires remedial action if (i) the auditor concludes that the omitted procedures impair its ability to support the previously issued opinion, and (ii) people are likely to rely on the report. If remedial action is required but the auditor is not able to perform the omitted procedures or alternative procedures that support the opinion, the standard directs the auditor to consult with counsel. Existing AS 2901 does not apply to ICFR audits or to attestation engagements.

2. Amendments to AS 2901

The Board believes that amendments to AS 2901 are appropriate to modernize the standard, incorporate the concepts and terminology introduced in QC 1000, and bring the standard into alignment

³⁶² AS 2905, rather than AS 2901, applies if the auditor subsequently learns of facts regarding the financial statements existing at the date of its report that might have affected its opinion. Paragraph .98 of AS 2201 is an analogous provision in the context of ICFR audits.

with the auditor's existing responsibility to obtain sufficient appropriate audit evidence to support the opinion.

QC 1000 introduces a new term, "engagement deficiency," defined as an instance of noncompliance with applicable professional or legal requirements by the firm, firm personnel, or other participants with respect to an engagement of the firm, or by the firm or firm personnel with respect to an engagement of another firm. For an engagement deficiency related to a completed engagement, QC 1000 requires firms to take action to address the engagement deficiency "in accordance with applicable professional and legal requirements" (e.g., AS 2901, AS 2905, AS 2201.98–.99).

The Board broadened the scope of AS 2901 to incorporate this new terminology, so that remedial action is required for engagement deficiencies for both financial statement audits and ICFR audits unless it was probable that the engagement report is not being relied upon.³⁶³ Reflecting this broader scope, the name of the standard was also changed to "Responding to Engagement Deficiencies After Issuance of the Auditor's Report."

a. Scope and Applicability (AS 2901.01–.02)

Note that, under PCAOB Rule 1001(a)(xii), "auditor" as used in AS 2901 means both firms and their associated persons.

i. Engagements Covered

Existing AS 2901 predates ICFR audit requirements and applies only to financial statement audits. The Board proposed to extend the scope of AS 2901 to cover engagement deficiencies in ICFR audits as well. Several commenters, generally firms, agreed with the proposal to extend the scope of AS 2901 to include engagement deficiencies in ICFR audits, and the Board adopted that change in scope.

Similar to the concept in existing AS 2901, the Board proposed that the revised standard would not apply to engagements where it is probable that the audit report is not being relied upon.³⁶⁴ The proposed standard included a note providing that the firm must treat an engagement report as being relied upon if the engagement

report is included in the most recent SEC filing on a form that requires its inclusion. One commenter pointed out that the use of the term "must" in the proposed note did not allow for the auditor to take into account situations that may indicate an auditor's report is not being relied upon even when the auditor's report is included in the most recent filing on an SEC form. Two commenters suggested that the standard should also exclude engagements where the issuance of the subsequent year's auditor's report is imminent.

The Board agrees that the standard should allow for circumstances where the auditor's report is included in the most recent filing on an SEC report, but the auditor may nonetheless conclude that the auditor's report is no longer being relied upon. However, in the Board's view, the fact that the issuance of the subsequent year's auditor's report is imminent is not determinative of whether the report continues to be relied upon.

The Board revised the note to paragraph .01 to provide that, in the absence of circumstances indicating that reliance is impossible or unreasonable (e.g., cessation of a trading market for issuer securities), inclusion of an auditor's report in the most recent filing on an SEC form that requires inclusion of such an auditor's report evidences that the report is being relied upon. The Board believes this is responsive to commenter concerns and allows for sufficient flexibility. The note has also been revised to clarify that an auditor's report can be included in an SEC filing either directly or through incorporation by reference.

The determination that an auditor's report is not being relied upon would primarily be influenced by whether the auditor's report and related financial statements are readily available and whether a trading market exists for the company's securities. Circumstances that may suggest the engagement report is no longer being relied upon could include:

- So much time has elapsed that the financial statements covered by the auditor's report are no longer required to be included in SEC periodic reports.
- The issuer's or broker-dealer's business has been dissolved or gone into liquidation.

ii. Compliance With AS 2905/AS 2201.98

Under the amendments, AS 2901 points the auditor to AS 2905 or AS 2201.98 to the extent they apply. This preserves the difference in treatment that exists under current auditing standards between situations where

financial statements and potentially the audit opinion may be in doubt (AS 2905 or AS 2201), and other circumstances where remedial action is required but there is no initial indication that the financial statements might be misstated (AS 2901).

iii. Deficiencies Covered

Existing AS 2901 applies when the auditor concludes that procedures considered necessary at the time of the audit in the circumstances then existing were omitted. As proposed, AS 2901 was extended to cover all engagement deficiencies identified. The Board believes it is more consistent with the basic philosophy of QC 1000 and better supports the ultimate goal of improving audit quality to require remedial action for all engagement deficiencies, regardless of whether the audit opinion is unsupported.

b. Activities To Address Engagement Deficiencies

AS 2901 currently requires remedial action when, due to omitted procedures that were considered necessary at the time of the audit, the auditor's opinion is not sufficiently supported. The required action is to perform the omitted procedures or alternative procedures that would support the opinion. If that is not possible, the auditor is directed to consult an attorney to determine an appropriate course of action.

Under the proposal, remedial action would be required for all engagement deficiencies—both those engagement deficiencies that affect the auditor's opinion and those that do not. Many commenters expressed concern with the proposal to require remedial actions for all engagement deficiencies, with one commenter suggesting that remedial actions should only be required for major deficiencies, and another commenter suggesting that the need for remedial actions should be assessed on a case-by-case basis, taking into account the severity of the engagement deficiency. Several commenters suggested that firms should be able to exercise judgment about whether remediation is necessary and observed that in practice most identified engagement deficiencies are remediated. Other commenters considered the proposed requirement overly prescriptive and one commenter suggested that the requirement was unnecessarily burdensome for instances where the auditor's report is adequately supported despite an identified engagement deficiency. On the other hand, two commenters expressed support for the Board's approach to the

³⁶³ See QC 1000.68b.

³⁶⁴ Under current AS 2901, the test is whether the auditor believes there are persons currently relying, or likely to rely, on the audit report. Under the final standard, the test would be whether it is probable that no one is relying, without reference to the auditor's belief. The term "probable" has the same meaning as described in the FASB ASC paragraph 450–20–25–1.

obligation to remediate engagement deficiencies, with one commenter stating that requiring remedial action for all identified engagement deficiencies, not just in situations where the auditor's opinion may be unsupported, would contribute to improving audit quality.

The Board continues to believe that requiring firms to take action to address all engagement deficiencies, whether related to an unsupported auditor's opinion or not, is appropriate and reinforces a firm's obligation to comply with all applicable professional and legal requirements, and adopted this requirement as proposed. As discussed below, when the opinion is appropriately supported, the firm may determine which actions to take in response to an engagement deficiency.

i. Addressing Engagement Deficiencies Related to an Unsupported Auditor's Opinion (AS 2901.03)

Under the proposal, in cases where the auditor did not obtain sufficient appropriate audit evidence to support the opinion, the auditor would have been required to either obtain additional evidence such that the opinion is adequately supported or take action to prevent future reliance on the report. One firm suggested that further guidance regarding these requirements would assist a firm in distinguishing between the engagement deficiencies that are subject to this provision rather than paragraph .04 (discussed below), or in the alternative, explicit alignment to the PCAOB's definition of a Part I.A or Part I.B deficiency.³⁶⁵ The Board is reluctant to incorporate terminology into its standards that does not have a fixed meaning under PCAOB rules and is subject to change.³⁶⁶ The Board also does not want to suggest that the requirements apply only to deficiencies identified by the PCAOB. However, in order to address this concern, paragraphs .03a and .03b were revised to make it explicit that the auditor's actions in paragraph .03b relate specifically to instances where the auditor is not able to obtain sufficient appropriate audit evidence to support the auditor's opinion.

The type of procedures that the auditor performs in response should be

guided by the type and amount of evidence needed to support the auditor's opinion. If the auditor is not able to obtain sufficient appropriate evidence to support the opinion, the auditor is required to take appropriate action to prevent future reliance on the audit report. The Board also amended AS 2201 as part of this rulemaking to include a reference to AS 2901 as a reminder of auditor responsibilities under that section with respect to audits of internal control over financial reporting.³⁶⁷

ii. Addressing All Other Engagement Deficiencies

Under the proposed standard, for all other deficiencies on audit engagements, the auditor would have been required to perform remedial actions, similar to those described in QC 1000.69, based on the auditor's determination of what action (corrective, preventive, or both) is appropriate based upon the specific facts and circumstances. The proposal described the following potential responses to engagement deficiencies:

- Take corrective action to completely remediate the deficiency, where appropriate.
- For deficiencies that cannot be completely remediated, remediate to the extent possible and implement measures to prevent recurrence. For example, if a Form AP was filed late, the auditor would not be able to remediate the lateness but could improve the controls over the filing process.
- Determine, based on the facts and circumstances, that no further remedial action is necessary, e.g., because of remedial actions already taken to respond to other deficiencies.

One commenter suggested including language in the lead-in to the note to paragraph .04 to further clarify that the actions a firm may take to remediate an engagement deficiency could be either corrective or preventive, or could be a combination of the two. The note in the final standard reflects this clarification.

Additionally, the term "remedial" was removed from the final standard in the lead-in to the note to paragraph .04 in order to encompass all actions required under applicable professional and legal requirements, some of which (e.g., notification to the board of directors or regulatory agencies) may not be remedial in nature.

c. Documentation

The proposed documentation requirement did not draw comment and was adopted as proposed.

When the auditor's response to engagement deficiencies involves adding additional information to the auditor's working papers, the requirements of AS 1215.16 will apply.

Under AS 2901, the auditor should document the actions taken pursuant to paragraphs .03 and .04 to address engagement deficiencies in an audit engagement where the audit report has previously been issued. This documentation requirement is consistent with the documentation requirements in proposed QC 1000.82c for all engagement deficiencies.

3. Related Amendments

The Board proposed to add provisions similar to AS 2901 to the standards for broker-dealer attestation engagements, AT No. 1 and AT No. 2, to prompt auditors of brokers and dealers to take appropriate action if they discover that the opinion or conclusion in a previously issued attestation report was not supported. Currently, those standards are silent as to the responsibilities that apply when a deficiency is identified after the engagement report is issued.

One commenter, who recommended changes to proposed AS 2901 (including that remediation should be required only when the auditor's opinion may not be supported), suggested that the same changes be incorporated into AT No. 1 and AT No. 2. For the reasons discussed above in the context of AS 2901, the Board does not believe such a limitation is appropriate. However, the Board made a conforming change, similar to a change made to AS 2901, to the note to clarify that the auditor must treat reports as being relied upon when the examination report (in the case of AT No. 1) or review report (in the case of AT No. 2) is included (either directly or through incorporation by reference) in an SEC filing on an SEC form that requires inclusion of such an examination report or review report. The Board also made revisions to the proposed requirements in AT No. 1 and AT No. 2 by removing the word "remedial" from the lead-in language to the notes in each of the respective standards in order to encompass all actions required under applicable professional and legal requirements, some of which (e.g., notification to the board of directors or regulatory agencies) may not be remedial in nature. With these modifications, the Board adopted the proposed amendments to AT No. 1 and AT No. 2.

The Board also amended AS 2201 as part of this rulemaking to include a reference to AS 2901 as a reminder of auditor responsibilities under that

³⁶⁵ Subsequent to the date of the comment letter, the PCAOB created an additional category, Part I.C deficiencies. Definitions of Part I.A, Part I.B, and Part I.C deficiencies are available on the PCAOB website at <https://pcaobus.org/oversight/inspections/inspection-procedures>.

³⁶⁶ As an example of how the Board's inspection reporting framework can change over time, in May 2023, the Board introduced several transparency enhancements to its inspection reports, including a new section of the inspection report focused on independence violations (Part I.C).

³⁶⁷ See Appendix 5, Other Amendments.

section with respect to audits of internal control over financial reporting.³⁶⁸

The Board did not propose to amend its interim attestation standards to include provisions similar to AS 2901. One commenter encouraged the Board to consider creating a separate attestation standard like AS 2901 to minimize repetition within each attestation standard, especially if the Board plans to adopt new standards beyond AT No. 1 and AT No. 2 in the future. At this time, the Board did not amend its interim attestation standards to include provisions similar to AS 2901, though it may consider doing so in the future.

Rescission of ET Section 102; Adoption of EI 1000; Related Amendments

1. Rescission of ET Section 102 and Adoption of EI 1000, Integrity and Objectivity

The Board rescinded an interim ethics and independence standard, ET 102, *Integrity and Objectivity*, replacing it with a new standard, EI 1000, *Integrity and Objectivity*. EI 1000 is based on existing ET 102, including its related interpretations codified as ET 102.02, .03, and .05, but reflects revisions that align PCAOB ethics requirements with the scope, approach, and terminology of QC 1000. To take one example, the new EI 1000 applies to registered public accounting firms and their associated persons rather than current AICPA “members” as referenced in ET 102.

Integrity and objectivity are foundational to the audit and critical to the performance of engagements under PCAOB standards. They lend credibility and engender trust in financial reporting. As the U.S. Supreme Court pointed out in *United States v. Arthur Young*:

By certifying the public reports that collectively depict a corporation’s financial status, the independent auditor assumes a public responsibility transcending any employment relationship with the client. The independent public accountant performing this special function owes ultimate allegiance to the corporation’s creditors and stockholders, as well as to the investing public. This “public watchdog” function demands that the accountant maintain total independence from the client at all times, and requires complete fidelity to the public trust.³⁶⁹

The responsibility to maintain integrity and objectivity is an important counterbalance to the risk that the auditor may be unduly influenced by company management or may be subject

to cognitive or other biases in performing the audit.³⁷⁰ In turn, an auditor’s integrity and objectivity can help to increase investor trust in financial reporting and strengthen capital markets.

Currently, paragraph .01 of ET 102 sets out three requirements that apply in the performance of a professional service: (i) maintaining integrity and objectivity, (ii) being free of conflicts of interest, and (iii) not knowingly misrepresenting facts or subordinating judgment. The remaining paragraphs of the rule and the relevant portions of ET 191 provide more detailed direction in specific contexts.

The Board proposed creating two overarching requirements in EI 1000: (i) maintaining integrity, which would include being honest and candid, not knowingly or recklessly misrepresenting facts, and not subordinating judgment; and (ii) maintaining objectivity, which would include being impartial, intellectually honest, and free of conflicts of interest. The proposal incorporated descriptions of integrity and objectivity that were substantially based on existing requirements in QC 20.10.³⁷¹

In addition to substantially recodifying existing requirements, the Board also proposed to clarify the scope of the rule and more closely align it with the scope, approach, and terminology of QC 1000.

With two clarifications discussed below, the Board adopted EI 1000 as proposed and rescinded ET 102.

a. General

As proposed, the Board modernized the standard and aligned it with other PCAOB standards and rules by renumbering it in accordance with the PCAOB’s reorganized standards framework, incorporating PCAOB terminology, and eliminating outdated provisions.

The final rule clarifies that the requirements of EI 1000 apply in connection with all responsibilities under “applicable professional and legal requirements” (as defined in QC 1000) and the firm’s related policies and procedures, whether in relation to the firm’s engagements, work the firm does

on other firms’ engagements, training, independence monitoring, or other activities that are part of or subject to the firm’s QC system. In addition, EI 1000 applies to registered firms and their associated persons, rather than to “members” as ET 102 currently provides.

The final rule also corrects a reference in EI 1000.02.b(2) from “materially false and misleading” to “materially false or misleading.”

One commenter supported the replacement of ET 102 with EI 1000, but recommended labeling it “OI” for Objectivity and Integrity. As described in the proposal, the Board created a designation not only for its standard on objectivity and integrity, but for future standards as well. The Board intends to use “EI” for all ethics and independence standards, just as it uses “AS” to designate auditing standards.

While one commenter confirmed that the terms used in EI 1000 are generally clear, another commenter recommended clarifying the expectations for the terms “being honest and candid” in EI 1000.02 and “being intellectually honest” in EI 1000.03. This language is drawn from existing QC 20.10, has a clear plain English meaning, and the Board believes should be well understood.

b. Integrity

EI 1000.02 notes that, as part of maintaining integrity, a firm and its associated persons must be “honest and candid.” This requirement is drawn from existing QC 20.10. The Board omitted the reference to “within the constraints of client confidentiality” in order to avoid suggesting that “client confidentiality” could limit a firm’s or its associated persons’ obligations to comply with the requirements of PCAOB rules or standards. This is consistent with the Board’s interpretation of QC 20.10, under which a firm or its associated persons must be honest and candid in complying with PCAOB rules and standards, including during PCAOB inspections. It also confirms, among other things, that associated persons have the ability to report wrongdoing within the firm and to the appropriate regulatory authorities without constraints of confidentiality, consistent with PCAOB rules and standards. Similar to current QC 20.10, EI 1000.02 does not address the requirements of client confidentiality beyond the requirements set forth in PCAOB rules and standards and applicable requirements of the Federal

³⁷⁰ See, e.g., *Auditing Accounting Estimates, Including Fair Value Measurements and Amendments to PCAOB Auditing Standards*, PCAOB Rel. No. 2018–005 (Dec. 20, 2018), at 30–35 (discussing auditor incentives and potential cognitive biases).

³⁷¹ QC 20.10 states: “Integrity requires personnel to be honest and candid within the constraints of client confidentiality. . . . The principle of objectivity imposes the obligation to be impartial, intellectually honest, and free of conflicts of interest.”

³⁶⁸ See Appendix 5, Other Amendments.

³⁶⁹ *United States v. Arthur Young*, 465 U.S. 805, 817–818 (1984).

securities laws, including the Sarbanes-Oxley Act.³⁷²

One commenter suggested that, rather than removing the reference to confidentiality, the Board should instead refer to IESBA Code Section 260 related to noncompliance with laws or regulations. In general, the Board does not incorporate by reference the concepts and terminology used by other standard setters. In relation to noncompliance with laws and regulations in particular, the Board has proposed its own new standard.³⁷³ If a new PCAOB standard in that area is ultimately adopted by the Board and approved by the SEC and makes it appropriate for the Board to amend EI 1000, the Board would of course intend for EI 1000 to align with its new standard rather than the IESBA code.

The proposal clarified that the responsibility to avoid factual misrepresentations covers not only knowing, but also reckless behavior, and that this responsibility applies to any knowing or reckless misrepresentation of fact, including situations where documents—such as work papers and communications with the PCAOB and the SEC—containing materially false or misleading information are knowingly or recklessly signed, permitted or directed to be signed, or left uncorrected by those with authority to correct them.

One commenter suggested that the concept of failing to correct a document that is materially false and misleading when having the authority to do so should be limited to circumstances in which the document was materially false and misleading “when made.” The Board agrees that the duty to correct is not unbounded, and generally applies at the time that a document is made (including when filed with or submitted to a regulatory authority). The Board notes, however, that while EI 1000 does not independently impose a duty to correct a document that was not materially false or misleading when made, such a duty may arise under other statutes, laws, or regulations, and the Board believes that in such a

circumstance, the failure to discharge that duty should also constitute a violation of EI 1000. The Board added language to EI 1000.02b to clarify the circumstances under which failure to correct a document would constitute a knowing or reckless misrepresentation of facts.

The Board proposed to broaden the responsibility to avoid subordination of judgment so it would apply to any dispute or disagreement over applicable professional and legal requirements or how to apply them. One commenter suggested that, as part of the provision on subordination of judgment, the Board should address the risk of supervisors exercising undue influence over subordinates in the same manner as under the AICPA Code of Professional Conduct.³⁷⁴ The relevant interpretive provision of the AICPA Code, 1.130.020, *Subordination of Judgment*, identifies undue influence by a supervisor as a potential threat to compliance with the AICPA’s Integrity and Objectivity Rule³⁷⁵ and provides safeguards to be applied when the threat is not at an acceptable level. The safeguards to be applied are essentially the same as the process required under EI 1000.02c, including research and consultation to determine whether the supervisor’s position is supportable, consultation with higher levels of management, and, if appropriate action is not taken, consideration of potential duties to notify third parties and consideration of the appropriateness of continuing a relationship with the firm. In addition to the provision in EI 1000, QC 1000 also addresses the risk of undue influence through a quality objective in the engagement performance component related to the appropriate resolution of differences in professional judgment,³⁷⁶ as well as general provisions that would apply to undue influence by a supervisor, including in the governance and leadership component,³⁷⁷ the ethics and independence component,³⁷⁸ and the resources component.³⁷⁹ The Board believes these provisions address the concerns raised by this commenter and have adopted the subordination of judgment provision of EI 1000 as proposed.

c. Objectivity

One commenter suggested that the Board could clarify the standard by including references to the AICPA or

IESBA concepts of conflict of interest. As noted above, it is not generally Board policy to incorporate by reference the concepts and terminology used by other standard setters. The Board also believes that a cross reference is not appropriate because EI 1000 addresses essentially the same conduct as the AICPA and IESBA provisions.

d. Rescission of Certain AICPA Interpretations

Additionally, the Board rescinded the former AICPA interpretations currently codified as ET 102.04, .06, and .07, which address members’ obligations to their employer’s external accountant, performance of educational services, and professional services involving client advocacy, respectively. These are generally not relevant to engagements performed under PCAOB standards. In addition, the matters addressed in paragraph .07 are either effectively superseded by 17 CFR 210.2–01 or more effectively addressed elsewhere in PCAOB standards (e.g., AS 2610, *Initial Audits—Communications Between Predecessor and Successor Auditors*).

2. Amendments to ET Section 191

In connection with EI 1000, the Board also proposed amending ET 191 by making a conforming amendment to paragraph .062 and rescinding paragraphs .130, .131, .170, .171, .186, .187, .198, .199, .202, and .203. The only commenter on this topic supported these amendments. The Board adopted the amendments as proposed. The interpretations the Board rescinded (addressing, respectively, use of the CPA designation by accountants not in public practice, service as a director of a bank, service on the board of directors of United Way or a similar federated fund-raising organization, providing services for company executives, and providing client advocacy services) are generally not relevant to engagements performed under PCAOB standards or are addressed elsewhere in PCAOB and SEC rules. The Board did not amend the portions of ET 191 that pertain to ET 101, which is not being substantively amended in this rulemaking.

3. Amendments to Rule 3500T, Interim Ethics and Independence Standards, and ET Section 101, Independence

The Board proposed amending paragraph (a) of Rule 3500T to eliminate the introductory phrase “In connection with the preparation or issuance of any audit report,” which it believes may cause the rule to be read unduly narrowly. The Board also proposed eliminating references to ET 102, *Integrity and Objectivity*, and

³⁷² As a general matter, the Uniform Accountancy Act excludes from the prohibition against voluntary disclosure, in part, “information required to be disclosed by the standards of the public accounting profession in reporting on the examination of financial statements or as prohibiting compliance with applicable laws, government regulations or PCAOB requirements.” AICPA, Uniform Accountancy Act (January 2018), available at <https://us.aicpa.org/content/dam/aicpa/advocacy/state/downloadabledocuments/uaa-eighth-edition-january-2018.pdf>.

³⁷³ See *Proposing Release: Amendments to PCAOB Auditing Standards related to a Company’s Noncompliance with Laws and Regulations And Other Related Amendments*, PCAOB Rel. No. 2023–003 (June 6, 2023).

³⁷⁴ AICPA Code of Professional Conduct 1.130.020, *Subordination of Judgment*.

³⁷⁵ *Id.* at 1.100.001.

³⁷⁶ QC 1000.42.c.

³⁷⁷ QC 1000.25.

³⁷⁸ QC 1000.33b, c., and f.

³⁷⁹ QC 1000.46a.

substituting a reference to EI 1000, *Integrity and Objectivity*. These proposed amendments did not receive any comment and were adopted as proposed.

Lastly, the Board amended paragraphs .04, .13, and .16 of ET 101, *Independence*, to conform the references to ET 102, which will be rescinded, to EI 1000.

Other Amendments

In connection with the adoption of QC 1000, the Board also adopted amendments to other professional standards, PCAOB rules, and PCAOB forms. As discussed in more detail below, these amendments:

- Align terminology, concepts, and cross-references with QC 1000;
- Rescind standards that are unnecessary in light of the adoption of QC 1000;
- Recodify certain provisions of requirements that are rescinded into other PCAOB standards and rules; and
- Make other technical and clarifying amendments.

The one commenter that addressed this topic generally supported the amendments and also recommended an amendment to PCAOB Rule 1001(p)(vi) to use the term “quality control standards” instead of “quality control policies and procedures.” The language used in PCAOB Rule 1001(p)(vi) is drawn from section 110(5) of Sarbanes-Oxley and the Board believes its rule should continue to align with that statutory provision.

These amendments are discussed further below.

1. Rescission of Rule 3400T, Interim Quality Control Standards; Adoption of Rule 3400, Quality Control Standards

These rule changes did not receive any comment and were adopted as proposed.

PCAOB Rule 3400T, *Interim Quality Control Standards*, requires registered public accounting firms and their associated persons to comply with the Board’s interim quality control standards. The Board rescinded Rule 3400T, including all current QC standards identified in the rule, which the Board adopted on an interim, transitional basis.³⁸⁰ The Board adopted

in its place a new rule, Rule 3400, to codify the auditor’s responsibilities for complying with the Board’s quality control standards.

2. Rescission of AS 1110, Relationship of Auditing Standards to Quality Control Standards

The Board received no comment on the proposed rescission of AS 1110 and rescinded it, as proposed.

At the time AS 1110 was issued, it served to describe the relationship between the then already-existing auditing standards and the new set of standards that governed a firm’s system of quality control. This relationship is now well understood by firms and clarified within QC 1000. In addition, the first two paragraphs of AS 1110 merely repeat the requirements to comply with the auditing and QC standards that are addressed by other PCAOB standards and rules. Accordingly, the Board rescinded AS 1110.

3. Adoption of AS 1310, Notification of Termination of the Auditor-Issuer Relationship

The Board adopted a new standard, AS 1310, which recodifies existing requirements of SECPS 1000.08(m), *Notification of the Commission of Resignations and Dismissals from Audit Engagements for Commission Registrants*, and applies those requirements to all firms and all issuer engagements. As noted above, the Board rescinded the QC standards that pertain only to firms that were SECPS members at the time the PCAOB was created. In lieu of the SECPS requirement, the Board adopted a new standard that requires the auditor to notify the SEC upon resignation or dismissal from an audit engagement of an issuer if the issuer does not report such change in a current report on Form 8-K.

The only commenter to address this proposed standard agreed that it could provide valuable and timely information to investors to alert them when audit committees have failed to fulfill their reporting responsibilities. The Board notes, however, that notifications provided under the current SECPS requirement might not be made publicly available. Nevertheless, the Board believes that notices provided to the SEC under the standard could provide

valuable information to the SEC. Therefore, the Board adopted the standard substantially as proposed, with a revision to conform to the precise language on Form 8-K. This requirement applies to all issuer engagements, regardless of whether the firm was a member of the SECPS and regardless of whether the issuer is required to report on Form 8-K.

4. Amendments to AT Section 101, Attest Engagements

These amendments did not receive any comment and were adopted as proposed.

The amendments to AT Section 101 align with the rescission of AS 1110 discussed above, by deleting the paragraphs that address the relationship of attestation standards to QC standards. Additionally, the deletion of footnote 23 removes language related to monitoring compliance with quality control policies and procedures, which is unnecessary in light of the adoption of QC 1000.

5. Amendments to Form 1, Application for Registration

The Board proposed to amend Form 1 to (i) refer to QC 1000 in the instructions in order to prompt firms to consider their obligations with respect to QC in connection with their application for registration, and (ii) add a new item whereby firms confirm whether they have designed a QC system in accordance with PCAOB standards. The only commenter to address this amendment agreed that the amendments would be appropriate. The Board adopted these amendments as proposed.

6. Amendments to Form 2, Annual Report Form

The Board proposed to amend Form 2 to add a new item whereby firms would confirm (i) that they have designed a QC system in accordance with PCAOB standards; and (ii) whether they were required to implement and operate a QC system in accordance with PCAOB standards at any time during the period of time covered by Form 2. The only commenter to address this amendment agreed that the amendments would be appropriate. The Board adopted these amendments as proposed.

7. Technical and Conforming Amendments

These amendments did not receive any comment and were adopted as proposed.

The Board implemented a number of technical and conforming amendments to align terminology and concepts in

³⁸⁰ Under PCAOB Rule 3400T(a), all firms are required to comply with QC standards as described in “the AICPA’s Auditing Standards Board’s Statements on Quality Control Standards, as in existence on April 16, 2003 (AICPA Professional Standards, QC §§ 20–40 (AICPA 2002)), to the extent not superseded or amended by the Board.” PCAOB Rule 3400T(b) requires certain firms to comply with QC standards as described in “the AICPA SEC Practice Section’s Requirements of Membership (d), (l), (m), (n)(1), and (o), as in

existence on April 16, 2003 (AICPA SEC Practice Section Manual 1000.08(d), (j), (m), (n)(1), and (o)), to the extent not superseded or amended by the Board.” PCAOB Rule 3400T(b). The note to Rule 3400T provides that those requirements “only apply to those registered public accounting firms that were members of the AICPA SEC Practice Section on April 16, 2003.”

existing standards and one PCAOB form with QC 1000.

The Board also implemented a technical amendment to the instructions to Form AP to clarify an exclusion from disclosing the identity of, and hours incurred by, accounting firms in certain circumstances. The Board, when it adopted Form AP, stated that it intended to exclude the reporting of “hours incurred in the audit of entities in which the issuer has . . . an investment” using the equity method of accounting.³⁸¹ Form AP currently excludes hours “of an accounting firm performing the audit of entities in which the issuer has an investment that is accounted for using the equity method,” but the Board is concerned that such language might be read to exclude all of the audit work performed by such an accounting firm on an audit, rather than only those hours spent performing the audit of entities in which the issuer has an investment accounted for using the equity method. The Board revised the instruction in Part IV of the form to exclude from its disclosure requirements the identity of, and hours incurred by, accounting firms “in performing” the audit of entities in which the issuer has an investment that is accounted for using the equity method, which clarifies that the identity of, and hours incurred by, such firms with respect to other work on the audit must be disclosed on Form AP, unless they are subject to other Form AP exclusions.

Effective Date

In the proposing release, the Board sought comment on the amount of time auditors would need before the proposed new quality control standard and the other proposed amendments to PCAOB standards, rules, and forms, if adopted by the Board and approved by the SEC, become effective. We proposed an effective date of December 15 of the year after approval by the SEC.

One commenter agreed that the proposed effective date should be reasonable in practical terms. Another commenter asserted that the standard is not clear on the effective date as it relates to design and implementation and operating effectiveness, and recommended that the Board allow firms significant time between the release of the final standard and its effective date. One commenter suggested that an 11-month period from the effective date to the first evaluation

date would not be practicable, and firms would need time to consider whether and how to transition from their evaluation date previously established under ISQM 1.

Several commenters suggested that if the standard is approved in 2023, and becomes effective on December 15, 2024, this would provide challenges to auditors. Some of these commenters further suggested that the proposed effective date would be particularly challenging for smaller firms that might not have already implemented ISQM 1 and do not have to implement SQMS 1 until December 15, 2025. Commenters suggested alternative effective dates such as December 15, 2025; 18 months after approval by the SEC and no sooner than December 15, 2025; the later of 12 months after approval by the SEC or December 15, 2025; or two years after SEC approval. One commenter suggested a phased approach such that the effective date would be different for firms that are annually inspected than for other firms, while other commenters suggested that firms that are required to implement incremental requirements based on the size of the firm should be provided additional time to implement the incremental requirements. One commenter suggested that an overly speedy adoption timeline could create unintended consequences such as disruption to QC systems and increased difficulty of getting buy-in on the proposed QC changes from stakeholders. Another commenter suggested that an additional one to two years may be needed for firms with less than 100 issuers, or that have not adopted ISQM 1, to develop and implement the additional monitoring, evaluation and remediation requirements. The commenter further suggested that a proposed initial evaluation date that is eleven and a half months after the effective date may not allow enough time for remediation and that the PCAOB should consider a longer onboarding process.

After considering the comments received subject to approval by the SEC, the final standard and related amendments to auditing standards, rules, and forms will take effect on December 15, 2025.

The Board believes that an effective date of December 15, 2025 strikes an appropriate balance between the benefits to investors of having QC 1000 take effect as promptly as practicable, while allowing sufficient time for firms to design and implement robust, QC 1000-compliant QC systems.

One commenter suggested the Board consider how mergers and acquisitions of firms would impact the effective date

for the standard, and suggested the Board consider similar guidance to the SEC that provides that issuers may exclude an acquired business's internal control over financial reporting from its assessment of internal control for up to one year or for one assessment. After consideration of the comment received, the Board appreciates that it could take time to fully integrate a newly acquired firm's QC system and perform an evaluation of its effectiveness. However, the Board does not believe that it is appropriate or consistent with its investor protection mandate to allow for a portion of a firm's QC system to be excluded from the annual evaluation. The Board believes that specific quality risks could arise as the result of a merger or acquisition, and that firms should be designing, implementing, and operating quality responses to address these as part of merger planning and execution. Furthermore, if, as a result of a merger or acquisition between registered public accounting firms, the resultant firm is unable to conclude that the QC system is effective as of the evaluation date, then the Board believes that it is essential that the firm has identified and is remediating the QC deficiencies that exist as a result of the merger or acquisition and is monitoring any impact on the firm's engagements.

Unlike ISQM 1 and SQMS 1, under QC 1000, the requirements for QC system evaluation are not being implemented on a delayed basis. When QC 1000 takes effect, all provisions of QC 1000 will take effect. Because the evaluation date of September 30 builds in over a nine-month delay between the effective date of the standard and the first evaluation date, the Board does not believe further delaying the effective date of the evaluation requirements would be necessary or appropriate. However, the first evaluation period will be of the period beginning on the effective date of the standard (*i.e.*, December 15, 2025) and ending on the next September 30, rather than the 12-month period ending on that September 30.

D. Economic Considerations and Application to Audits of Emerging Growth Companies

Economic analysis is an important aspect of the rulemaking process. This economic analysis describes the baseline for evaluating the economic impacts of the rulemaking, the need for rulemaking, its expected economic impacts (including benefits, costs, and potential unintended consequences), and reasonable alternatives considered. Due to data limitations, much of the economic analysis is qualitative in

³⁸¹ See *Improving the Transparency of Audits: Rules to Require Disclosure of Certain Audit Participants on a New PCAOB Form and Related Amendments to Auditing Standards*, PCAOB Rel. No. 2015-008 (Dec. 15, 2015), at 26.

nature; however, where reasonable and feasible, the analysis incorporates quantitative information, including information from PCAOB inspections of registered firms.

The Board has sought information relevant to the economic analysis over the course of this rulemaking.³⁸² To the extent that commenters expressed views related to the economic analysis, many commenters generally agreed with the need for QC 1000, but some commenters raised concerns with certain impacts of the proposed standard. Several commenters expressed concerns about costs associated with certain key requirements, such as documentation. Some commenters suggested that the economic analysis should more explicitly consider costs that could disproportionately impact smaller and mid-size firms. Some commenters asserted potential unintended consequences with the proposed standard, including demand on staff resources and potential competitive effects, while other commenters suggested alternatives to help manage costs associated with certain proposed requirements, such as the 100-issuer threshold and evaluation and reporting dates. Some commenters offered a quantitative perspective regarding impacts. Several commenters referenced additional academic research for the Board's consideration. The Board considered all the comments received, including the quantitative perspectives and academic research the comments referenced, and has developed the following economic analysis that evaluates the expected benefits and costs of the final requirements, discusses potential unintended consequences, and facilitates comparison to alternative actions considered.

Baseline

The discussion above provides an overview of current PCAOB QC standards; summarizes observations from PCAOB oversight activities; and describes developments in the auditing environment since the adoption of current PCAOB QC standards, including the actions of other standard setters. This section expands on that discussion by describing additional aspects of the economic baseline against which the economic impacts of the requirements can be considered and presenting other relevant information on the audit services market for issuers and broker-dealers. Specifically, this expanded discussion includes:

- Three complementary proxies for the level of compliance with professional standards applicable to the performance of engagements, derived from PCAOB inspections data. Analysis of these proxies informs the baseline for considering the expected benefits of the requirements (e.g., improved compliance with professional standards).³⁸³
- Information on resources that U.S. global network firms ("GNFs") invest in their QC systems. As the requirements are expected to result in changes to some firms' QC systems, this information informs the baseline for considering the expected costs of the requirements.
- Changes firms have made to their QC systems to remediate QC deficiencies identified by PCAOB inspections staff and presents QC deficiencies related to firms' management of their audit practices. This discussion provides information on the evolution of QC systems and informs the evaluation of the need for and the economic impacts of the requirements.
- A concise survey of academic literature on quality-threatening behaviors that suggest certain weaknesses in some QC systems in practice.
- Key assumptions regarding how QC systems are likely to evolve absent the requirements.

In describing the baseline,³⁸⁴ the analysis presents anonymized and aggregated summary statistics regarding deficiencies included in past PCAOB inspection reports. Since PCAOB inspection reports do not consider broker-dealer engagements, the analysis also presents anonymized and aggregated summary statistics regarding audit and attestation engagement deficiencies included in annual reports on the PCAOB's interim inspection program related to audits of brokers and dealers. The following background

³⁸³ See below for further discussion.

³⁸⁴ The scope of the information on inspections and remediation efforts presented in the baseline section is limited to those firms that are subject to inspection under Sarbanes-Oxley; specifically, firms that provide one or more audit reports for an issuer, broker, or dealer and firms that play a substantial role in the preparation or furnishing of such audit reports. See section 104(a)(1), (2), and (b)(1) of Sarbanes-Oxley, 15 U.S.C. 7214(a)(1), (2), and (b)(1). In particular, PCAOB's analysis of deficiencies included in past PCAOB inspection reports does not include registered firms that would be subject only to design requirements on the basis that they do not perform "engagements" as defined in QC 1000. Based on Form 2 reporting as of June 30, 2023, approximately 60% of registered firms reported that they had not issued an audit report for an audit of an issuer or broker-dealer or played a substantial role in such an engagement during the preceding 12 months.

information associated with this quantitative inspection information bears emphasizing:

- QC deficiencies presented in Part II of a PCAOB inspection report³⁸⁵ may relate to: (1) a firm's management of its audit practice or (2) a firm's performance of audit procedures.³⁸⁶ QC deficiencies of the first type refer to the operation of QC policies and procedures. For example, a QC deficiency related to a firm's management of its audit practice may be identified through inspection staff's review of how the firm considers and addresses risks in connection with engagement acceptance and continuance decisions. QC deficiencies of the second type are inferred through analysis of deficiencies identified during inspections of individual issuer audit engagements. For example, a QC deficiency related to a firm's performance of audit procedures may be identified through inspection staff review of the performance of audit procedures related to management's accounting estimates.³⁸⁷

- Deficiencies presented in Part I.A of an inspection report represent deficiencies in issuer audits selected for inspection that were of such significance that the Board believes that the firm, at the time it issued its audit report, had not obtained sufficient appropriate audit evidence to support its opinion on the issuer's financial statements and/or internal control over financial reporting. As part of the PCAOB's process for reviewing firms' QC systems, PCAOB inspection teams evaluate whether identified deficiencies in individual audits indicate a defect or potential defect in a firm's QC system. However, a Part I.A deficiency does not, on its own, necessarily imply significant defects or potential defects in a firm's QC system. The PCAOB inspection team will consider the nature, significance, and frequency of deficiencies and related firm methodology, guidance, practices, and possible root causes when assessing whether Part I.A deficiencies in individual audits indicate significant

³⁸⁵ Part II of a firm's inspection report includes any criticisms of, and potential defects in, the firm's QC system, that were communicated to the firm as part of a PCAOB inspection. As required under Sarbanes-Oxley, any QC deficiencies observed during a PCAOB inspection are not included in the public portion of the relevant inspection report when first issued. If a firm does not address to the Board's satisfaction criticisms of, and potential defects in, the firm's QC system within 12 months after the issuance of the PCAOB inspection report, Part II of the report will be issued publicly to include such deficiencies. Additional information is available on the PCAOB website at <https://pcaobus.org/oversight/inspections/remediation>.

³⁸⁶ See PCAOB Rel. No. 2012-003, at 8-9.

³⁸⁷ See PCAOB Rel. No. 2012-003, at 8.

³⁸² See PCAOB Rel. No. 2022-006; PCAOB Rel. No. 2019-003.

defects or potential defects in a firm's QC system that should appear in Part II of the firm's inspection report.³⁸⁸

- The Dodd-Frank Wall Street Reform and Consumer Protection Act gave the PCAOB oversight of auditors of broker-dealers registered with the SEC. In June 2011, the PCAOB established an interim program to inspect these auditors and identify and address with them any significant issues observed in their audits and related attestation engagements. This interim inspection program remains in place today. The inspection processes for audits of issuers and broker-dealers are different in many respects, including the applicable laws, rules, and professional standards; the inspection selection process; inspection focus areas; and reporting of inspection results. In particular, unlike PCAOB inspections of issuer audits, which lead to an inspection report for each inspected firm, the PCAOB issues a single annual report on the interim inspection program related to audits of broker-dealers, which summarizes the results of the PCAOB's inspections of broker-dealer engagements performed during the previous year.³⁸⁹

- The analysis of QC and issuer audit deficiencies below is presented over a twelve-year period for three separate categories of firms: (1) U.S. GNFs, (2) other firms having more than five inspected issuer engagements, and (3) other firms having five or fewer inspected issuer engagements.³⁹⁰

³⁸⁸ Additional information on PCAOB inspection procedures is available on the PCAOB website at <https://pcaobus.org/oversight/inspections/inspection-procedures>.

³⁸⁹ See *Annual Report on the Interim Inspection Program Related to Audits of Brokers and Dealers*, PCAOB Rel. No. 2023-005 (Aug. 10, 2023). Additional information on the interim inspection program is available on the PCAOB website at <https://pcaobus.org/resources/information-for-audit-firms/information-for-auditors-of-broker-dealer>.

³⁹⁰ Time trends can help to identify associative relationships and may suggest how the audit market could evolve absent the requirements. However, time trends in PCAOB inspection deficiencies depend on, among other things, changes in the set of firms and engagements selected for inspection. Firms that issue 100 or fewer audit reports for issuers are, in general, inspected at least once every three years. Firms that issue audit reports for more than 100 issuers are inspected annually. Therefore, the set of inspected firms and engagements is not fixed year over year.

Categorizing inspections information among firms of different sizes helps account for the significantly skewed variation in audit firm size present in the audit market.³⁹¹ The 2011 through 2022 period is used because information from earlier inspection years is less comparable and information from later inspection years was not completely available as of the date of this analysis. Information was preliminary for the 2022 inspection year as of the date of the PCAOB staff analysis.

- The analysis of audit and attestation engagement deficiencies included in annual reports on the PCAOB's interim inspection program related to audits of brokers and dealers below is presented over a 12-year period. The 2011 through 2022 period is used because 2011 was the first year of the interim inspection program and 2022 is the most recent year that data are available as of the date of this analysis. Information on deficiencies associated with attestation examinations or reviews is not available prior to 2015 because 2015 was the first full year during which the PCAOB was able to review attestation engagements of brokers and dealers.

1. Proxies Related to Compliance With Professional Standards

This subsection presents analyses of three quantitative proxies for the level of compliance with professional standards and thus provides information on the baseline for considering the key expected benefit of the requirements: improved compliance with professional standards. Specifically, it presents information on Part I.A deficiencies, QC deficiencies related to audit performance, and broker-dealer engagement deficiencies, from the audits or engagements PCAOB inspected. Overall, the analyses suggest that some firms' QC systems may not be providing the required reasonable assurance. Broker-dealer engagements and issuer audits performed by firms

³⁹¹ Current PCAOB QC standards recognize that the nature, extent, and formality of a firm's QC policies and procedures should take into account various factors, including the size of the firm. Because PCAOB QC assessments also take into account these factors, the number of QC deficiencies across each of the three categories of firms are not directly comparable. See PCAOB Rel. No. 104-2006-077, at 9-10.

other than U.S. GNFs appear to have more room for improvement on average based on the period examined.

a. Part I.A Deficiencies

Figure 1 presents for categories of PCAOB-inspected audits the percentage of inspected issuer audits having at least one Part I.A deficiency. PCAOB staff calculated the Part I.A deficiency rates by dividing the number of inspected issuer audits that had at least one Part I.A deficiency by the number of inspected issuer audits for each given year. The Part I.A deficiency rate should not be equated with the rate of audit deficiencies across the whole issuer population. It may understate the true rate of issuer audit deficiencies because some deficiencies may not rise to the level of a Part I.A deficiency and because PCAOB inspectors do not inspect all aspects of inspected audits. However, it may also overstate the true rate of issuer audit deficiencies because PCAOB inspectors generally focus their attention on, among other things, audits and audit areas with a heightened risk of material misstatement.

Despite these potential biases in the Part I.A deficiency rate, the Board believes that the Part I.A deficiency rates presented in Figure 1 are indicative of underlying issuer audit deficiencies. However, there are two caveats that may impact the interpretation of Figure 1. First, because the audits with deficiencies are not drawn from a random sample, the deficiencies could be driven in part by changes over time in the proportion of reviewed audits that were selected based on characteristics associated with high-risk audits. Second, PCAOB inspections staff review more focus areas during reviews of U.S. GNF issuer audits than they do during reviews of other firms' issuer audits, increasing the opportunity for a reviewed U.S. GNF issuer audit to have at least one Part I.A deficiency.

For U.S. GNFs, Figure 1 shows that the percentage of inspected issuer audits having at least one Part I.A deficiency was 37% in 2011 and 30% in 2022. For other firms, the percentage has remained in the 31% to 53% range.

Figure 1. Percentage of Inspected Issuer Audits Having at Least One Part I.A Deficiency (2011-2022)

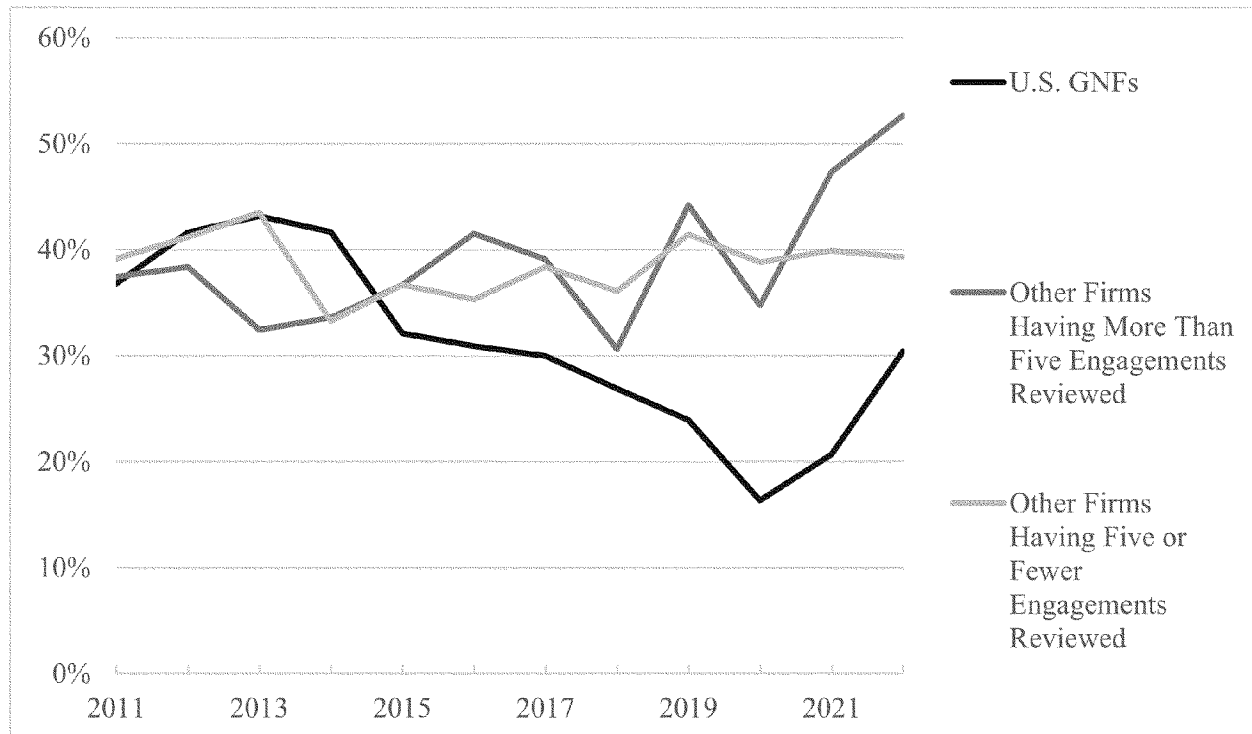
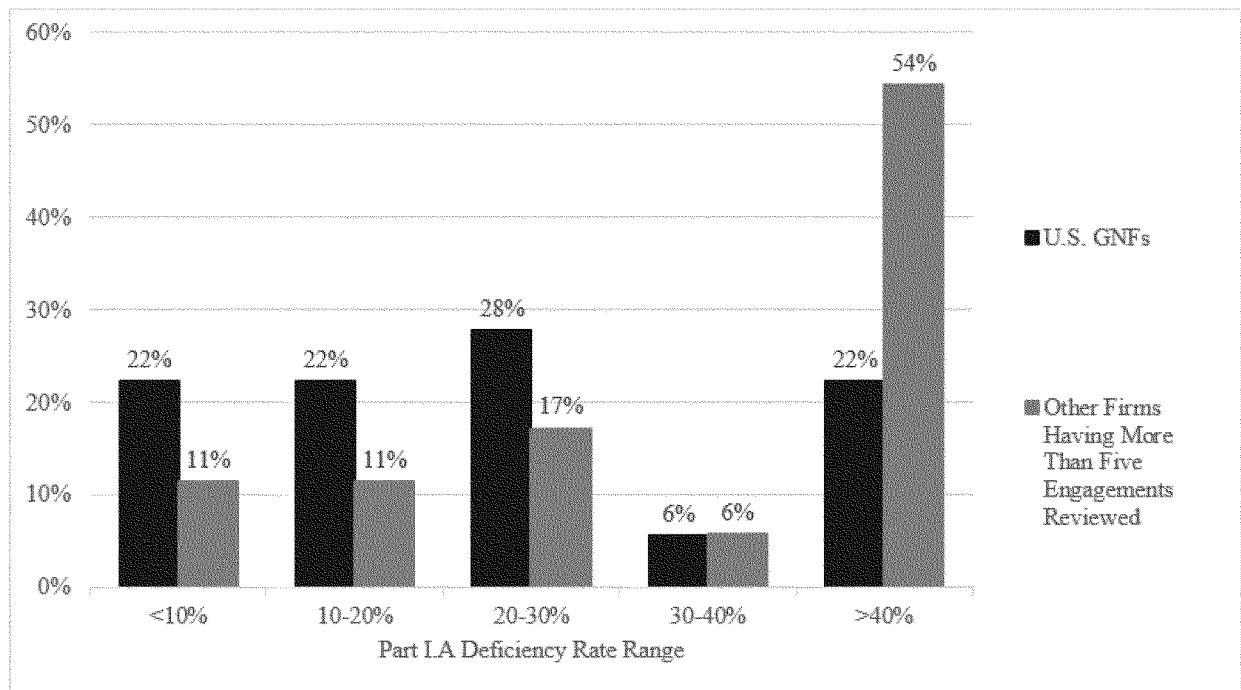


Figure 2 provides additional insight on how the percentage of inspected issuer audits having at least one Part I.A deficiency varies by firm. Each bar indicates the percentage of 2020, 2021, and 2022 firm inspections with a Part I.A deficiency rate within a given range.

For example, Figure 2 indicates that 22% of all 2020, 2021, and 2022 U.S. GNF inspections and 11% of all 2020, 2021, and 2022 inspections of other firms with more than five inspected engagements had a Part I.A deficiency rate below 10%. Figure 2 excludes firm

inspections with five or fewer inspected engagements because the Part I.A deficiency rate is a less informative proxy in these cases due to the small number of inspected engagements.

Figure 2. Percentage of Firm Inspections with a Part I.A Deficiency Rate within a Given Range (2020-2022)



Note: During the 2020, 2021, and 2022 inspection years, there were in total 18 inspections of U.S. GNFs and 35 inspections of other firms having more than five engagements reviewed.

b. QC Deficiencies Related to Audit Performance

Figure 3 presents the average number of QC deficiencies related to audit performance per inspected firm. QC deficiencies related to audit performance are inferred through analysis of inspections of individual audits and thus represent another proxy for the level of compliance with professional standards. To prepare Figure 3, PCAOB staff counted the number of distinct QC deficiencies

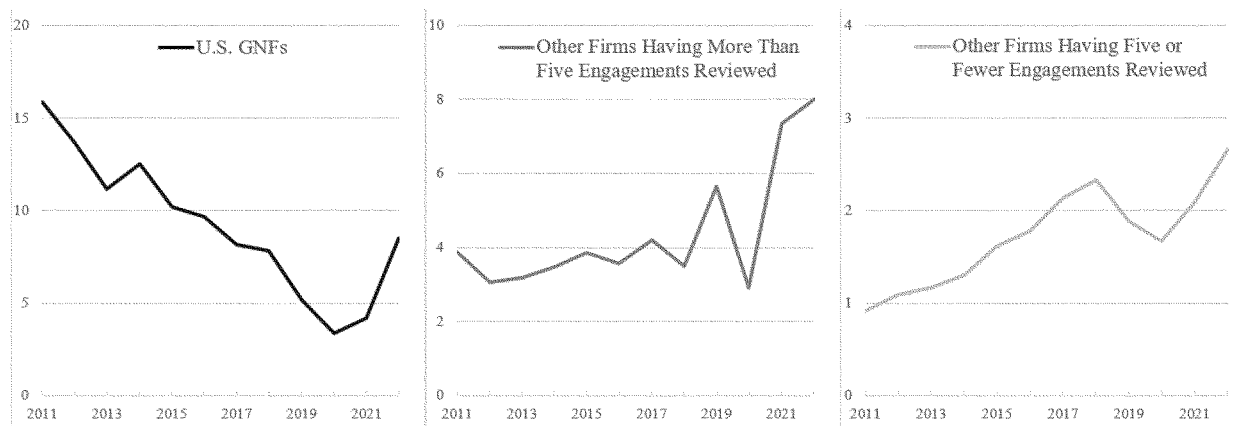
related to audit performance in Part II of PCAOB inspection reports. Staff assigned a zero to firm inspections that resulted in no QC deficiencies related to audit performance. Staff then calculated averages per inspected firm by year and firm group, assigning equal weight to each QC deficiency regardless of its nature or whether it was a repeat deficiency. While the total number of QC deficiencies is not readily comparable across each of the three categories of firms because of differences in inspection approach, the averages have ranged between 3.3 and 15.8 for U.S. GNFs, between 2.9 and 8.0 for other firms having more than five engagements reviewed, and between 0.9

and 2.7 for other firms having five or fewer engagements reviewed. Two caveats may impact the interpretation of Figure 3. First, starting in 2019, the PCAOB revised its approach to identifying QC deficiencies related to audit performance. The Board believes this policy change reduced the number of QC deficiencies related to audit performance for some of the inspections of non-affiliated firms (“NAFs”) but not for the U.S. GNFs. Second, the variability in the deficiency rate in the second panel may be due in part to year-over-year changes in the set of firms having more than five engagements reviewed, which may include triennial firms.³⁹²

³⁹² Firms that issued audit reports with respect to 100 or fewer issuers during the prior calendar year

(“triennial firms”) must be inspected at least once every three years.

Figure 3. Average Number of QC Deficiencies Related to Audit Performance Per Inspected Firm (2011-2022)



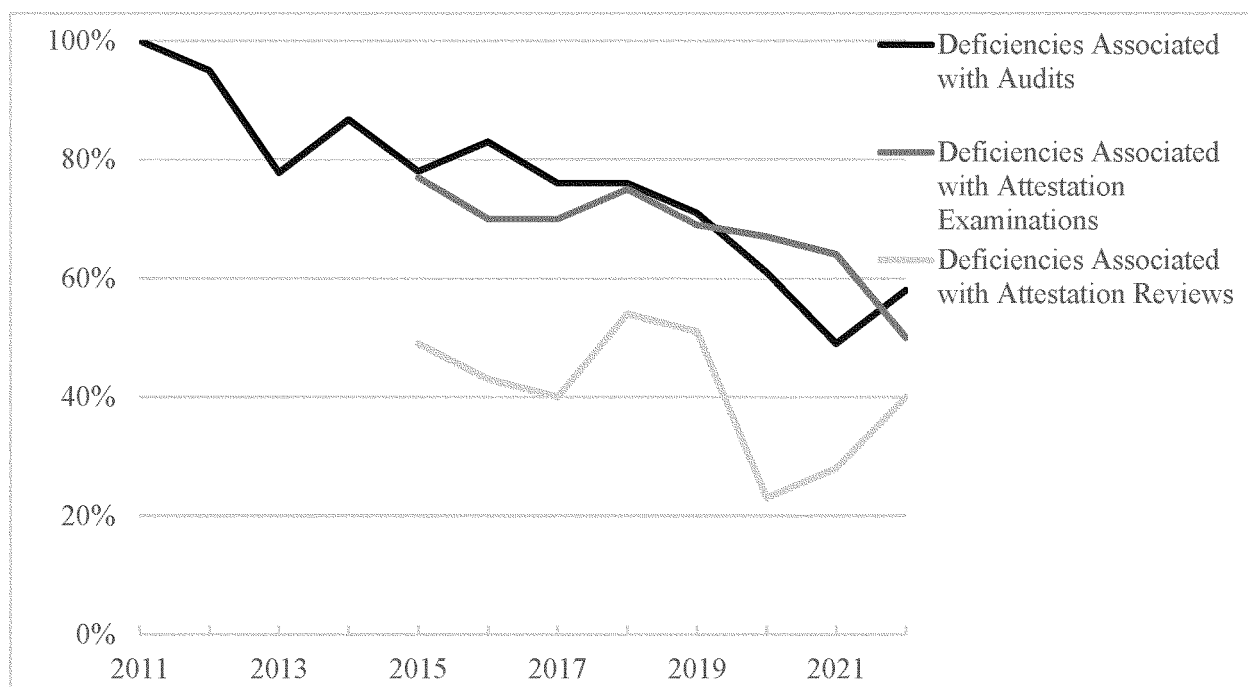
c. Broker-Dealer Engagement Deficiencies

Figure 4 presents the percentage of broker-dealer audits with deficiencies and the percentage of attestation engagements and reviews with deficiencies, among the selected sample

of PCAOB engagements. The percentages are reproduced from the PCAOB's annual reports on the interim inspection program related to the audits of broker-dealers. The percentages are equal to the number of inspected engagements for which there were

deficiencies divided by the number of inspected engagements. The percentages of audits and attestation examinations with deficiencies have remained greater than 45%. The percentage of attestation reviews with deficiencies has remained in the 23% to 54% range.

Figure 4. Percentages of Broker-Dealer Engagements with Deficiencies (2011-2022)



2. Resources Associated With QC systems

Firms implement their QC systems through a set of policies and procedures. These policies and procedures vary across firms, reflecting both the principles-based nature of current QC standards and the variation in firms' particular circumstances. To inform the baseline for considering the expected costs of the requirements, PCAOB staff: (1) held initial discussions with U.S. GNFs to obtain qualitative information regarding the resources associated with their QC systems and (2) conducted a voluntary survey of U.S. GNFs on the resources they employ to design, implement, and operate QC policies and procedures. Overall, the information indicates the resources that U.S. GNFs are already devoting to the design, implementation, and operation of QC policies and procedures related to the ISQM 1 requirements.

The U.S. GNF survey requested both qualitative and quantitative information for each of the eight QC system components specified by ISQM 1: risk assessment, governance and leadership, independence and ethics, acceptance and continuance, engagement performance, resources (human, intellectual, and technological), information and communication, and monitoring and remediation.³⁹³ In addition, the survey requested qualitative and quantitative information related to network requirements or network services, evaluation of the QC system, and documentation.³⁹⁴ The request referred to ISQM 1 explicitly in order to facilitate comparability of the information gathered across firms and to the proposed QC standard.

All six U.S. GNFs provided qualitative information and five provided quantitative information. Staff received completed surveys between June 23 and July 6, 2021. The respondents provided the information as of their most recently completed fiscal year-end or QC system assessment date.

The qualitative information that PCAOB staff received indicates that U.S. GNFs' QC policies and procedures are extensive and highly integrated with the audit process. Multiple groups, teams, functions, and individuals participate in the design, implementation, and operation of QC policies and procedures. Engagement teams play a key role in the operation of many QC policies and procedures. Among other QC-related responsibilities, engagement

teams often assist in acceptance and continuance decisions; initiate consultations; help maintain accurate and complete information within independence systems; attend training; and initiate and complete individual performance evaluations.

The U.S. GNFs' QC systems involve multiple IT systems that support QC activities and may also serve other operational functions. These QC systems may also rely upon work or services provided by the firm's global network and/or third-party vendors. Global network services may relate to development and maintenance of technological and intellectual resources (e.g., global audit methodology, global independence and assurance policies and procedures, etc.) or monitoring the quality of audit services performed by network affiliates. The firms report making ongoing investments in their QC systems, including implementation of new technology that supports QC activities.

The quantitative portion of the survey asked the U.S. GNFs to estimate: (1) the number of firm personnel involved in designing, implementing, or operating QC policies and procedures on an annual basis (by partner vs. non-partner); (2) the percentage of their time committed; and (3) the expected percentage change in QC resource requirements as of December 15, 2022, when ISQM 1 became effective.³⁹⁵ PCAOB staff asked the firms to include in their estimates only those resources directly related to the design, implementation, and operation of QC policies and procedures over audits of U.S. issuers and broker-dealers. In cases where removing time spent on QC policies and procedures related to audits of private companies was prohibitively difficult or impossible, staff asked firms to include this time in their estimates and describe the inseparable portion. Firms reported that their QC policies and procedures generally apply across their entire audit practice and thus their estimates typically included resources dedicated to QC systems over engagements

³⁹⁵ More specifically, staff asked U.S. GNFs to estimate the number of firm personnel who are directly involved in the design, implementation, or operation of each QC system component by commitment level (i.e., <10%, 10–40%, 40–60%, 60–90%, or >90% of the individual's time). If an individual committed time to multiple QC system components, staff asked firms to count the individual once for each QC component and to indicate the time committed to each component. For example, if an individual committed 100% of the individual's time to the firm's QC system, 50% to acceptance and continuance and 50% to monitoring and remediation, firms were asked to count the individual under the 40–60% commitment level for both components.

performed under PCAOB standards as well as audits performed under other standards.

In initial discussions with the U.S. GNFs, firms reported that identifying all firm personnel hours related to their QC systems would be an enormous challenge. To make the data request feasible, PCAOB staff directed firms to exclude from their quantitative estimates time spent by engagement teams operating QC policies and procedures (e.g., performing independence procedures, planning for or engaging in consultations, executing the firm's methodology) and facilitating internal inspections. Staff also asked firms to exclude: (1) time spent by firm personnel attending training; (2) time spent by individuals on compliance with personal independence policies and procedures; (3) time spent performing engagement quality reviews of individual engagements; and (4) any resources invested at the global network level to design, implement, or operate QC policies or procedures. The qualitative information received from the firms suggests that these aspects of their QC systems are likely resource-intensive.

Table 1 summarizes the quantitative information received in aggregate form. It presents the means and standard deviations of partner, non-partner, and total full-time equivalents (FTEs) by QC system component.³⁹⁶ The means provide a sense of average scale while the standard deviations provide a sense of average variability across the firms. Overall, the means presented in Table 1 indicate that U.S. GNFs commit a mean of 647.9 total FTEs to designing, implementing, and operating their QC policies and procedures. QC policies and procedures related to: (1) independence and ethics utilize a mean of 189.9 total FTEs and (2) human,

³⁹⁶ To calculate the means presented in Table 1, staff summed the number of individuals directly involved in the design, implementation, or operation of each QC system component, weighting individuals by the mid-point of their respective commitment level and divided by the number of firms that were able to provide data for the respective QC system component. The "Total" row mean is equal to the number of individuals directly involved in the design, implementation, or operation of any QC system component, weighting individuals by the mid-point of their respective commitment level divided by five (i.e., the number of firms that provided quantitative information). Therefore, the "Total" row mean does not equal the sum of the QC component-level means. The standard deviations presented in Table 1 were calculated without Bessel corrections. The standard deviation for the "Other" component is equal to the geometric mean of the standard deviations of the network requirements or network services, evaluation of the system of quality management, and documentation components. The Board's data are insufficient to account for potential covariances between these components.

³⁹³ See paragraphs 23–33 and 35–47 of ISQM 1.

³⁹⁴ See paragraphs 48–60 of ISQM 1.

intellectual, and technological resources utilize a mean of 252.6 total FTEs. Non-partner FTEs are roughly 3.5 times partner FTEs, but partners play a relatively larger role in the governance and leadership, engagement performance, and monitoring and remediation components of QC systems. The standard deviations presented in Table 1 indicate that the average variability across firms is 499.9 total FTEs. The average variability for the independence and ethics component is 173.9 total FTEs and for the resources component is 295.2 total FTEs.

The mean “Total” row values presented in Table 1 may include some underestimation error for several reasons. First, some firms were unable to reasonably estimate all of the resources for certain components, most notably for the governance and leadership component. Second, firms were generally unable to reliably estimate the cost of IT infrastructure

that supports the QC system. Third, firms were generally unable to reliably estimate the portion of common-pool resources attributable to the QC system that support broader operational or financial objectives of the firm. Fourth, due to estimation challenges as described above, firms were directed to exclude certain resources from their estimates, including time spent by engagement teams executing QC policies and procedures and time spent by firm personnel attending training.

By contrast the mean “Total” row values may also include some overestimation error. For example, firms broadly reported that their QC policies and procedures apply to both issuer and non-issuer audits and it would generally be infeasible to identify firm personnel hours related to quality control over issuer audits only. In these cases, PCAOB staff asked firms to include both issuer and non-issuer QC hours in their estimates.

Some firms were unable to separately break out the level of resources committed to designing, implementing, and operating QC policies and procedures for risk assessment, information and communication, network requirements or network services, evaluation of the system of quality management, and documentation. These firms distributed these resources across the remaining components. While this leads to some overestimation error to the remaining components, the information provided by the firms that were able to separately break out these components indicates that these components are relatively less resource-intensive and, therefore, the overestimation error is likely small. This overestimation error does not apply to the mean “Total” row values because any errors in how the firms allocated across components nets out when summing.

TABLE 1—RESOURCES ASSOCIATED WITH U.S. GNFS’ QC POLICIES AND PROCEDURES

	Partner (FTEs) mean	Non-partner (FTEs)	Total (FTEs)			
			Per firm	St. dev	Mean per firm	St. dev
Risk Assessment	2.1	1.4	4.6	2.3	6.7	2.4
Governance and Leadership	10.0	5.8	9.2	9.3	19.2	14.7
Independence and Ethics	17.7	15.7	172.2	164.2	189.9	173.9
Acceptance and Continuance	11.5	6.1	13.7	13.8	25.2	14.2
Engagement Performance	38.9	23.1	52.8	29.0	91.7	49.0
Resources	42.4	36.6	210.2	267.0	252.6	295.2
Information and Communication	2.6	2.6	8.6	3.3	11.2	4.9
Monitoring and Remediation	22.1	7.1	34.9	15.1	56.9	21.1
Other*	4.1	0.6	11.6	2.5	15.6	2.8
Total	143.6	85.3	504.3	428.9	647.9	499.9

*The “Other” category includes network requirements or network services, evaluation of the system of quality management, and documentation.

Most U.S. GNFS were unable to provide precise estimates regarding expected future changes in QC system resource requirements as of December 15, 2022, when ISQM 1 became effective. The qualitative information provided by the firms indicates that: (1) additional resources likely were required; (2) some of the U.S. GNFS had assigned teams to manage ISQM 1 implementation; and (3) the risk assessment component and the evaluation of the system of quality management component were expected to require the most additional resources.

The Board also received information regarding non-GNFS through the proposal comment process that indicates that non-GNFS have devoted resources to the design, implementation, and operation of QC policies and procedures related to ISQM 1 and/or SQMS 1 requirements. One commenter

noted that national firms with fewer than 500 issuers have significantly fewer resources associated with QC policies and procedures.³⁹⁷ One commenter noted that firms have invested significant time and resources to comply with the existing quality management standards from other standard setters, and another commenter noted that, at least with respect to QC roles and responsibilities, smaller firms have already designed their processes to accord with ISQM 1

³⁹⁷ The commenter asserted that the mean total FTEs reported in Table 1 for GNFS represent approximately 10% of partners and employees for firms of similar size and composition to the commenter. However, the commenter also reported having approximately 90% fewer partners and employees than some U.S. GNFS and approximately 99% fewer than other U.S. GNFS, so the resources reported in Table 1 would likely be scaled down accordingly for the commenter and similar sized firms.

and SQMS 1. One firm explained that its implementation efforts of ISQM 1 required a great deal of evaluation of risks and related responses, and another firm explained that its implementation effort was a significant undertaking that involved a number of people across the firm. Another commenter suggested that non-U.S. firms may be incorporating quality management frameworks adopted by their local regulator, such as CPAB’s Quality Management System framework. Several commenters representing non-GNF perspectives focused more generally on the provisions of QC 1000 that diverge from ISQM 1 and SQMS 1, which the Board understands as implying that these firms had expended resources to construct and operate quality control systems in compliance with those standards. However, at least one

commenter noted that for small firms that do not need to comply with ISQM 1, efforts may be ongoing to implement SQMS 1, indicating that some of these firms may be focused on resources for design and may not yet be spending resources to operate QC policies in line with SQMS 1.

One commenter noted research that appears to be too tangential or unrelated to actual resources employed by firms to be useful for advancing the Board's understanding of resources associated with the design, implementation, and operations of their QC systems. The commenter noted that most academic studies related to resources employed by NAFs or foreign affiliates of GNFs in the design, implementation, and operations of their QC systems focus on either: (1) the contributions of internal quality reviews to audit firm quality³⁹⁸ or (2) the association of audit firm network arrangements, as proxies for resources, with audit quality.³⁹⁹ For example, one study suggests that when firms have formal connections via networks or large alliance arrangements, audits within those arrangements have similar levels of quality,⁴⁰⁰ which the commenter noted may imply that formal connections are a vehicle to share and enforce QC practices.

3. Developments in Firms' QC Policies and Procedures

This subsection provides information on the evolution of firms' QC policies and procedures. First, it describes changes firms have made to their QC policies and procedures to remediate QC deficiencies identified in inspection reports. Second, it presents analyses of QC deficiencies related to firms' management of their audit practices. QC deficiencies related to firms' management of their audit practice relate to the operation of QC policies and procedures. Overall, the information suggests that QC policies and procedures are advancing.

Many firms have implemented a number of changes to their QC systems

to remediate their QC deficiencies.⁴⁰¹ Changes brought about through remediation are wide-ranging and can touch upon all major elements of the current QC standards. The nature, extent, and formality of changes made by a firm vary based on the size of the firm and the nature and complexity of its practice. Examples of changes made by various types of firms include:⁴⁰²

- Adding in-process review and coaching programs to assist engagement teams in certain challenging areas, including ICFR and accounting estimates;
- Creating a committee to evaluate partner performance in relation to audit quality and issuing an accountability framework with penalties for negative audit quality events;
- Implementing a new template that includes guidance to facilitate the assessment and documentation of partner performance, including guidance related to various performance metrics (such as technical knowledge; leadership and training skills; and compliance with firm quality control policies and procedures);
- Requiring audit partners to articulate specific actions they will take to achieve performance goals related to audit quality and providing additional guidance and information around partner workload management;
- Implementing new policies and procedures for engagement teams to focus on obtaining a thorough understanding of how issuers initiate, record, process, and report significant classes of transactions and how that information is recorded in the financial statements;
- Hiring external consultants to work with the firm to develop a new ICFR audit approach;
- Adding new leadership positions to the internal inspection program, developing new analysis and reporting of internal inspection findings, and beginning to disseminate findings more broadly;
- Creating a committee to provide oversight on the firm's audit quality

initiatives and a new leadership position to drive consistency across regions; and

- Implementing new templates that provide guidance related to performing a root cause analysis, including identifying areas of a firm's quality control process to perform causal analysis, collecting relevant data, and documenting the results.

The Board took these observations into account in developing QC 1000.

One commenter, an academic, referred to a recent unpublished study examining how firms change and manage their QC systems, which involved surveying QC leaders from eight U.S. accounting firms. The commenter reported that the three most common changes currently underway in the firms relate to: (1) engagement monitoring and use of data analytics; (2) organizational structure (*e.g.*, a dedicated ISQM team, independent advisors); and (3) a more proactive approach to identifying QC issues.⁴⁰³

Figure 5 presents the average number of QC deficiencies related to firms' management of their audit practice per inspected firm. To prepare Figure 5, PCAOB staff counted the number of distinct QC deficiencies related to firms' management of their audit practice in Part II of PCAOB inspection reports. Staff assigned a zero to firm inspections that resulted in no QC deficiencies related to the firm's management of its audit practice. Staff then calculated averages per inspected firm by year and firm group, assigning equal weight to each QC deficiency regardless of its nature or whether it was a repeat deficiency. While the total number of QC deficiencies are not readily comparable across each of the three categories of firms, the averages have ranged between 0.8 and 10.2 for U.S. GNFs, between 0.3 and 1.5 for other firms having more than five engagements reviewed, and between 0.3 and 0.6 for other firms having five or fewer engagements reviewed.

³⁹⁸ See, *e.g.*, Richard W. Houston and Chad M. Stefaniak, *Audit Partner Perceptions of Post-Audit Review Mechanisms: An Examination of Internal Quality Reviews and PCAOB Inspections*, 27 *Accounting Horizons* 23 (2013); Denise Hanes Downey and Kimberly D. Westermann, *Challenging Global Group Audits: The Perspective of US Group Audit Leads*, 38 *Contemporary Accounting Research* 1395 (2021); Olof Bik and Reggy Hooghiemstra, *Cultural Differences in Auditors' Compliance with Audit Firm Policy on Fraud Risk Assessment Procedures*, 37 *Auditing: A Journal of Practice & Theory* 25 (2018).

³⁹⁹ See, *e.g.*, Renee Flasher and Kristy Schenck, *Exploring PCAOB Inspection Results for Audit Firms Headquartered Outside of the US*, 37 *Journal*

of International Accounting, Auditing and Taxation 1 (2019); Philip Keejae Hong, David S. Kerr, and Casper E. Wiggins, *PCAOB International Inspections: Updates and Extensions*, 26 *International Journal of Auditing* 279 (2022); Matthew S. Ege, Young Hoon Kim, and Dechun Wang, *Do Global Audit Firm Networks Apply Consistent Audit Methodologies across Jurisdictions? Evidence from Financial Reporting Comparability*, 95 *The Accounting Review* 151 (2020).

⁴⁰⁰ See Flasher and Schenck, *Exploring PCAOB Inspection Results* 1.

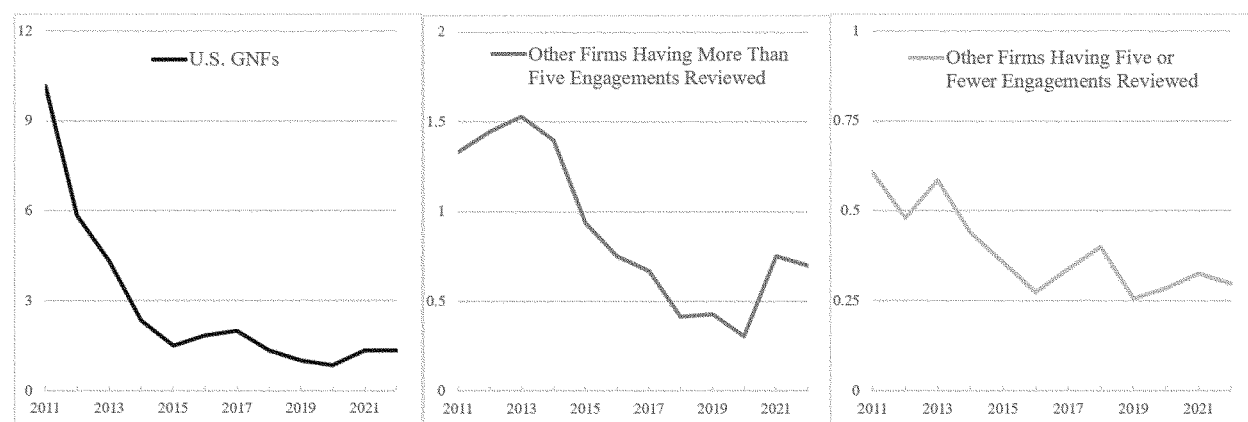
⁴⁰¹ Additional information about the PCAOB remediation process is available on the PCAOB

website at https://pcaobus.org/oversight/inspections/remediation/remediation_process.

⁴⁰² Examples are drawn from firms' Rule 4009 submissions. A Rule 4009 submission is a submission prepared by a firm, pursuant to PCAOB Rule 4009, concerning the ways in which a firm has addressed a QC criticism. For additional background, see PCAOB Rel. No. 104–2006–077.

⁴⁰³ The commenter also reported that the three most commonly described ideal changes relate to: (1) engagement monitoring and use of data analytics; (2) human talent-related initiatives such as changes to hiring and promotion practices; and (3) client risk assessment processes. Ideal changes are described as changes the QC leaders would make if the firms did not face resource constraints.

Figure 5. Average Number of QC Deficiencies Related to Firms' Management of Their Audit Practice per Inspected Firm (2011-2022)



4. Academic Literature on Quality-Threatening Behaviors and Quality Control

This subsection discusses academic research on behaviors that suggest certain weaknesses in QC systems in practice. Over time, researchers have documented a variety of quality-threatening behaviors, including “premature sign-off of audit procedures, failure to perform required procedures, inappropriate reductions in substantive testing or other forms of under-auditing, underreporting of time, inadequate adjustments of audit procedures in response to changing risk conditions, and over-reliance on management explanations of unusual deviations in analytical procedures.”⁴⁰⁴

Some commenters provided additional specific examples of quality-threatening behaviors. For example, one commenter reported that some academic research finds auditors may not always be objective when deciding on the acceptability of management’s accounting choices or when recommending audit adjustments that would reduce reported income or assets.⁴⁰⁵ Citing a settlement between a

U.S. GNF and the Federal Deposit Insurance Corporation, another commenter asserted that one firm’s QC system failed when one of the firm’s engagement teams inappropriately assigned a responsibility to an intern.

Research suggests that quality-threatening behaviors imply a failure of QC systems to provide reasonable assurance of compliance.⁴⁰⁶ Moreover, some research suggests that, while not solely responsible, certain features of firms’ management of their audit practice may encourage quality-threatening behaviors.⁴⁰⁷ For example, experimental research suggests that certain cognitive biases in auditor evaluation and reward systems may inadvertently deter appropriate professional skepticism⁴⁰⁸ and other studies suggest that partner reward systems at some firms may weight revenue generation more heavily than professional competencies.⁴⁰⁹ Some research finds that reward systems

oriented toward revenue generation are associated with lower proxies for audit quality.⁴¹⁰ Synthesizing several recent academic studies, one commenter reported that an excessive focus on commercialism, rather than professionalism, continues to be a dominant focus within firms’ cultures and may negatively impact audit quality.⁴¹¹ The commenter also reported that academic research indicates quality-threatening behaviors may be negatively associated with audit team leadership characteristics.⁴¹² For

⁴¹⁰ See, e.g., Jürgen Ernstberger, Christopher Koch, Eva Maria Schreiber, and Greg Trompeter, *Are Audit Firms’ Compensation Policies Associated With Audit Quality?* 37 *Contemporary Accounting Research* 218 (2020); Thomas Riise Johansen and Jeppe Christoffersen, *Performance Evaluations in Audit Firms: Evaluation Foci and Dysfunctional Behavior*, 21 *International Journal of Auditing* 24 (2017).

⁴¹¹ See, e.g., Christina Thomas Alberti, Jean C. Bedard, Olof Bik, and Ann Vanstraelen, *Audit Firm Culture: Recent Developments and Trends in the Literature*, 31 *European Accounting Review* 59 (2022); Chris Carter and Crawford Spence, *Being a Successful Professional: An Exploration of Who Makes Partner in the Big 4*, 31 *Contemporary Accounting Research* 949 (2014); Ken H. Guo, *The Institutionalization of Commercialism in the Accounting Profession: An Identity-Experimentation Perspective*, 35 *Auditing: A Journal of Practice and Theory* 99 (2016); Claire-France Picard, Sylvain Durocher, Yves Gendron, *The Colonization of Public Accounting Firms by Marketing Expertise: Processes and Consequences*, 37 *Auditing: A Journal of Practice & Theory* 191 (2018); Jonathan S. Pyzoha, Mark H. Taylor, and Yi-Jing Wu, *Can Auditors Pursue Firm-Level Goals Nonconsciously on Audits of Complex Estimates? An Examination of the Joint Effects of Tone at the Top and Management’s Specialist*, 95 *The Accounting Review* 367 (2020).

⁴¹² See, e.g., Noel Harding and Ken T. Trotman, *The Effect of Partner Communications of Fraud Likelihood and Skeptical Orientation on Auditors’ Professional Skepticism*, 36 *Auditing: A Journal of Practice & Theory* 111 (2017); Sean A. Dennis and

before Audit Completion, 57 *Journal of Accounting Research* 355 (2019).

⁴⁰⁶ See, e.g., Jean C. Bedard, Donald R. Deis, Mary B. Curtis, and J. Gregory Jenkins, *Risk Monitoring and Control in Audit Firms: A Research Synthesis*, 27 *Auditing: A Journal of Practice & Theory* 187 (2008).

⁴⁰⁷ See, e.g., David P. Donnelly, Jeffrey J. Quirin, and David O’Byrne, *Attitudes Toward Dysfunctional Audit Behavior: The Effects of Locus of Control, Organizational Commitment, and Position*, 19 *Journal of Applied Business Research* 95 (2003).

⁴⁰⁸ See, e.g., Joseph F. Brazel, Scott B. Jackson, Tammie J. Schaefer, and Bryan W. Stewart, *The Outcome Effect and Professional Skepticism*, 91 *The Accounting Review* 1577 (2016).

⁴⁰⁹ See, e.g., Marie-Laure Vandenhaute, Kris Hardies, and Diane Breesch, *Professional and Commercial Incentives in Audit Firms: Evidence on Partner Compensation*, 29 *European Accounting Review* 521 (2020).

⁴⁰⁴ Monika Causholli and W. Robert Knechel, *An Examination of the Credence Attributes of an Audit*, 26 *Accounting Horizons* 631, 647 (2012).

⁴⁰⁵ See, e.g., Kathryn Kadous, Jane S. Kennedy, and Mark E. Peecher, *The Effect of Quality Assessment and Directional Goal Commitment on Auditors’ Acceptance of Client-Preferred Accounting Methods*, 78 *Accounting Review* 759 (2003); Christopher Koch and Steven E. Salterio, *The Effects of Auditor Affinity for Client and Perceived Client Pressure on Auditor Proposed Adjustments*, 92 *Accounting Review* 117 (2017); Lori Shefchik Bhaskar, Patrick E. Hopkins, and Joseph H. Schroeder, *An Investigation of Auditors’ Judgments When Companies Release Earnings*

example, skeptical auditors may be penalized if they do not find a material misstatement,⁴¹³ audit managers sometimes reward senior associates for performing the unethical act of under-reporting time when the client is more desirable,⁴¹⁴ or while internal inspections lead to increased auditor effort in the inspection year, positive internal inspection results may lead auditors to decrease effort in the future.⁴¹⁵

An excessive focus on commercial objectives may also lead to undue focus on cost-control in the execution of audits. For example, in one study, audit staff report working, on average, five hours per week, and sometimes 20 hours per week, past the threshold where they feel audit quality begins to deteriorate.⁴¹⁶ In another study, audit staff report working on average 72 hours per week during busy season.⁴¹⁷ Other research finds that a heavier workload in the fieldwork phase of the audit is negatively associated with proxies for audit quality⁴¹⁸ and that high levels of time pressure are positively associated with audit quality-threatening behaviors.⁴¹⁹ Referring to academic research, one commenter reported that

Karla M. Johnstone, *A Field Survey of Contemporary Brainstorming Practices*, 30 Accounting Horizons 449 (2016); Jodi L. Gissel and Karla M. Johnstone, *Information Sharing During Auditors' Fraud Brainstorming: Effects of Psychological Safety and Auditor Knowledge*, 12 Current Issues in Auditing P1 (2018).

⁴¹³ See, e.g., Brazel, et al., *The Outcome Effect*.

⁴¹⁴ See, e.g., Christopher P. Agoglia, Richard C. Hatfield, Tamara A. Lambert, *Audit Team Time Reporting: An Agency Theory Perspective*, 44 Accounting, Organizations & Society 1 (2015). Desirability in this case is determined by various situational and contextual factors that are inherent to the client, such as a client that is convenient for the audit manager's work schedule, a client that is easy to get to, client management that the audit manager gets along particularly well with personally, a client that is within the audit manager's industry of interest, or an engagement that involves an influential partner at the audit manager's office.

⁴¹⁵ See, e.g., Daniel Aobdia and Reining C. Petacchi, *The Effect of Audit Firm Internal Inspections on Auditor Effort and Financial Reporting Quality*, 98 The Accounting Review 1 (2023).

⁴¹⁶ See Julie S. Persellin, Jaime J. Schmidt, Scott D. Vandervelde, and Michael S. Wilkins, *Auditor Perceptions of Audit Workloads, Audit Quality, and Job Satisfaction*, 33 Accounting Horizons 95 (2019).

⁴¹⁷ See Dana R. Hermanson, Richard W. Houston, Chad M. Stefaniak, and Anne M. Wilkins, *The Work Environment in Large Audit Firms: Current Perceptions and Possible Improvements*, 10 Current Issues in Auditing A38 (2016).

⁴¹⁸ See, e.g., Brant E. Christensen, Nathan J. Newton, and Michael S. Wilkins, *How Do Team Workloads and Team Staffing Affect the Audit? Archival Evidence from US Audits*, 92 Accounting, Organizations and Society 1 (2021).

⁴¹⁹ See, e.g., Tobias Svanström, *Time Pressure, Training Activities and Dysfunctional Auditor Behaviour: Evidence from Small Audit Firms*, 20 International Journal of Auditing 42 (2016).

engagement-level pressures, including meeting budgets, can affect audit quality.⁴²⁰ The commenter also reported that academic research finds that audit partner workload compression is negatively associated with audit quality.⁴²¹

One commenter noted academic papers that study various factors that may impact audit quality but appear to be too tangential or unrelated to quality-threatening behaviors that suggest certain weaknesses in QC systems. The commenter included academic research that studies the relationship between audit teams' use of the work of other participants and audit quality.⁴²² The commenter also cited research from other countries that finds evidence that partner-related characteristics influence audit quality.⁴²³ In addition, the

⁴²⁰ See, e.g., Mark E. Peecher, M. David Piercey, Jay S. Rich, and Richard M. Tubbs, *The Effects of a Supervisor's Active Intervention in Subordinate's Judgments, Directional Goals, and Perceived Technical Knowledge Advantage on Audit Team Judgments*, 85 Accounting Review 1763 (2010); Koch and Salterio, *The Effects* 117; and William F. Messier and Martin Schmidt, *Offsetting Misstatements: The Effect of Misstatement Distribution, Quantitative Materiality, and Client Pressure on Auditors' Judgments*, 93 Accounting Review 335 (2018).

⁴²¹ See, e.g., Jun Chen, Wang Dong, Hongling Han, and Nan Zhou, *Does Audit Partner Workload Compression Affect Audit Quality?* 29 European Accounting Review 1021 (2020).

⁴²² See, e.g., Candice T. Hux, *Use of Specialists on Audit Engagements: A Research Synthesis and Directions for Future Research*, 39 Journal of Accounting Literature 23 (2017); Joseph F. Brazel, Tina D. Carpenter, and J. Gregory Jenkins, *Auditors' Use of Brainstorming in the Consideration of Fraud: Reports from the Field*, 85 The Accounting Review 1273 (2010); J. Gregory Jenkins, Eric M. Negangard, and Mitchell J. Oler, *Getting Comfortable on Audits: Understanding Firms' Usage of Forensic Specialists*, 35 Contemporary Accounting Research 1766 (2018); Emily E. Griffith, Jacqueline S. Hammersley, and Kathryn Kadous, *Audits of Complex Estimates as Verification of Management Numbers: How Institutional Pressures Shape Practice*, 32 Contemporary Accounting Research 833 (2015); Nathan H. Cannon and Jean C. Bedard, *Auditing Challenging Fair Value Measurements: Evidence from the Field*, 92 The Accounting Review 81 (2017); Steven M. Glover, Mark H. Taylor, and Yi-Jing Wu, *Current Practices and Challenges in Auditing Fair Value Measurements and Complex Estimates: Implications for Auditing Standards and the Academy*, 36 Auditing: A Journal of Practice & Theory 63 (2017); J. Efrim Boritz, Natalia Kochetova-Kozloski, and Linda Robinson, *Are Fraud Specialists Relatively More Effective than Auditors at Modifying Audit Programs in the Presence of Fraud Risk*, 90 The Accounting Review 881 (2015); Aleksandra "Ally" B. Zimmerman, Dereck Barr-Pulliam, Joon-Suk Lee, and Miguel Minutti-Meza, 61 Journal of Accounting Research 1363 (2023).

⁴²³ See, e.g., W. Robert Knechel, Ann Vanstraelen, and Mikko Zerni, *Does the Identity of Engagement Partners Matter? An Analysis of Audit Partner Reporting Decisions*, 32 Contemporary Accounting Research 1443 (2015); Yanyan Wang, Lisheng Yu, Yuping Zhao, *The Association between Audit-Partner Quality and Engagement Quality: Evidence from Financial Report Misstatements*, 34 Auditing: A Journal of Practice & Theory 81 (2015); W. Robert

commenter noted academic papers that find evidence that non-audit services can negatively affect audit quality through mechanisms other than independence impairment.⁴²⁴ Moreover, the commenter included research that has examined the association between PCAOB inspections of audit firms and audit quality but does not appear to relate specifically to weaknesses in QC systems.⁴²⁵

5. Assumptions Regarding the Baseline

Absent the requirements, the Board believes that many firms would continue to design and implement new QC policies and procedures or modify existing QC policies and procedures in response to evolving audit market conditions, technological advances, PCAOB oversight activities, internal monitoring, and actions of other standard setters.⁴²⁶ The Board believes that most firms have either implemented ISQM 1 or will implement SQMS 1 when it goes into effect. PCAOB-registered firms with an international presence or that are part of a global network will likely find it efficient to design and implement a QC system that complies with both PCAOB standards and ISQM 1 and have that

Knechel, Lasse Niemi, and Mikko Zerni, *Empirical Evidence on the Implicit Determinants of Compensation in Big 4 Audit Partnerships*, 51 Journal of Accounting Research 349 (2013); Simon Dekeyser, Ann Gaeremynck, W. Robert Knechel, and Marleen Willekens, *The Impact of Partners' Economic Incentives on Audit Quality in Big 4 Partnerships*, 96 The Accounting Review 129 (2021); Herman Van Brenk, Barbara Majoor, and Arnold M. Wright, *The Effects of Profit-Sharing Plans, Client Importance, and Reinforcement Sensitivity on Audit Quality*, 40 Auditing: A Journal of Practice & Theory 107 (2021).

⁴²⁴ See, e.g., Erik L. Beardsley, Andrew J. Imdieke, and Thomas C. Omer, *The Distraction Effect of Non-audit Services on Audit Quality*, 71 Journal of Accounting and Economics 1 (2021); Dain C. Donelson, Matthew Ege, Andrew J. Imdieke, and Eldar Maksymov, *The Revival of Large Consulting Practices at the Big 4 and Audit Quality*, 87 Accounting, Organizations and Society 1 (2020).

⁴²⁵ See, e.g., Daniel Aobdia, *The Impact of the PCAOB Individual Engagement Inspection Process—Preliminary Evidence*, 93 The Accounting Review 53 (2018); Inder K. Khurana, Nathan G. Lundstrom, and K.K. Raman, *PCAOB Inspections and the Differential Audit Quality Effect for Big 4 and Non-Big 4 US Auditors*, 38 Contemporary Accounting Research 376 (2021); Lindsay M. Johnson, Marsha B. Keune, and Jennifer Winchel, *U.S. Auditors' Perceptions of the PCAOB Inspection Process: A Behavioral Examination*, 36 Contemporary Accounting Research 1540 (2019); Kimberly D. Westermann, Jeffrey Cohen, and Greg Trompeter, *PCAOB Inspections: Public Accounting Firms on "Trial"*, 36 Contemporary Accounting Research 694 (2019); Bradley E. Hendricks, Wayne R. Landsman, and F. Peña-Romera, *The Revolving Door between Large Audit Firms and the PCAOB: Implications for Future Inspection Reports and Audit Quality*, 97 The Accounting Review 261 (2022).

⁴²⁶ See above for additional background on the actions of other standard setters.

system operate over their entire assurance practice. For similar reasons, PCAOB-registered firms with a private company audit practice will likely find it efficient to design and implement a QC system that complies with both PCAOB standards and SQMS 1 and have that system operate over their entire assurance practice.

Supporting that view, comment letters on the proposing release suggest that some firms have already designed and implemented, or are in the process of designing and implementing, QC policies and procedures consistent with the requirements of other QC standards. For example, one commenter said that nearly all firms are subject to multiple QC standards, including ISQM 1. Another commenter said that firms in Europe have invested heavily to implement ISQM 1. Another commenter said that nearly all firms that will need to adopt QC 1000 are also subject to other QC standards, including ISQM 1 and SQMS 1, and that firms have already invested significant time and resources to comply with them. Another commenter presented its recent survey research that finds firms have started to prepare for ISQM 1 and SQMS 1 implementation but that there is variation in their level of preparedness.⁴²⁷ Overall, the comments indicate that firms have made progress implementing the quality control standards of other standard setters.

The Board's view is also informed by several public information sources. First, the AICPA website indicates that most registered firms that are headquartered in the U.S. were reviewed as part of the AICPA's Peer Review program since 2019, and therefore were required to comply with AICPA QC standards at that time.⁴²⁸ Second, among the U.S.-headquartered firms that signed an issuer or broker-dealer audit opinion in 2021 but were not peer reviewed since 2019, most indicate on their web page that they perform audits or tax services that require them to comply with AICPA QC standards. Third, most foreign jurisdictions require companies to have a statutory audit performed, which the Board believes suggests that most registered firms headquartered in foreign jurisdictions likely perform audits under IAASB QC standards. Finally, firms' annual reports filed with

the PCAOB on Form 2 for the April 1, 2022, through March 31, 2023, reporting period indicate that most firms collected fees for services aside from the performance of issuer audits and therefore may have performed services subject to AICPA or IAASB QC standards during that time. Overall, the Board believes these public information sources support its view that most firms will be complying with either ISQM 1 or SQMS 1. Furthermore, most firms that will not be complying with ISQM 1 or SQMS 1 will likely be scaled-applicability firms and therefore less impacted by the requirements.

Need

1. Introduction and summary

This section discusses the problem that the requirements are intended to address and explains how the requirements address it. Overall, three observations suggest that there is a problem that the requirements will help to address:

- Under current PCAOB QC standards, a firm's QC system is required to provide reasonable assurance that the firm's personnel comply with applicable professional standards, regulatory requirements, and the firm's standards of quality.⁴²⁹ However, the audit market does not currently provide sufficient incentives for all firms to design, implement, and operate QC systems that achieve this requirement on a consistent basis.
- Current PCAOB QC standards contain higher-level principles and do not directly address recent developments in QC. As a result, the current regulatory baseline is not rigorous enough to sufficiently support PCAOB oversight, further undermining firms' and individuals' incentives to provide the required reasonable assurance.

- The lack of incentives to provide the required reasonable assurance is evidenced by the prevalence of audit performance deficiencies—i.e., Part I.A deficiencies and QC deficiencies related to audit performance discussed above—which, as noted in the first two observations above, suggest that some firms' QC systems are not providing the required reasonable assurance.

The requirements of QC 1000 will help address the problem by establishing three overarching features, which are discussed further below:

- The requirements mandate firms' QC systems to more proactively assess risks and monitor and remediate deficiencies.

- The requirements improve accountability within firms with respect to the reasonable assurance objective.

- The requirements use more precise language and include more prescriptive requirements in key areas to reflect best practices.

2. The Audit Market Does Not Provide Sufficient Incentives for All Firms To Design, Implement, and Operate QC Systems That Provide Reasonable Assurance

A diverse set of investors and other financial statement users need and request high quality audits. However, due to the presence of asymmetric information⁴³⁰ and positive externalities⁴³¹ in the audit market, there are not sufficient incentives for all firms to design, implement, and operate QC systems that provide reasonable assurance that a firm's personnel comply with applicable professional standards, regulatory requirements, and the firm's standards of quality. This lack of incentives can lead to an inefficient allocation of audit services as described in the following paragraphs.

Investors and other financial statement users cannot easily observe the services performed by an auditor. This information asymmetry creates a risk that, unbeknownst to investors and other financial statement users, auditors may under-audit and gather insufficient audit evidence to support their opinion or may otherwise depart from applicable requirements. Economic theory refers to this effect as moral hazard.⁴³² While this may enable the auditor to do less work and reduce potential conflicts with company management and may therefore lead to short-run benefits for the auditor, it may also lead to a net welfare loss in the audit market as a whole.⁴³³

⁴³⁰ See N. Gregory Mankiw, *Principles of Economics* 468 (6th ed. 2008) ("A difference in access to relevant knowledge is called an information asymmetry.").

⁴³¹ See Mankiw, *Principles of Economics* 196 ("An externality arises when a person engages in an activity that influences the well-being of a bystander but neither pays nor receives any compensation for that effect. . . . If it is beneficial, it is called a positive externality.").

⁴³² See, e.g., Mankiw, *Principles of Economics* 468 ("Moral hazard is a problem that arises when one person, called an agent, is performing some task on behalf of another person, called the principal. If the principal cannot perfectly monitor the agent's behavior, the agent tends to undertake less effort than the principal considers desirable.").

⁴³³ See, e.g., Mankiw, *Principles of Economics* 145 ("Consumer surplus and producer surplus are the basic tools that economists use to study the welfare of buyers and sellers in a market. Consumer surplus is the benefit that buyers receive from participating in a market, and producer surplus is the benefit that sellers receive. It is therefore natural

Continued

⁴²⁷ See Christie Hayne, Market E. Peecher, Jeff Pickerd, and Yuepin (Daniel) Zhou, *Managing Quality Control Systems: How Audit Firms Experience and Navigate Conflicting Institutional Demands*, available at <https://ssrn.com/abstract=4339512>.

⁴²⁸ See AICPA Peer Review web page, available at <https://us.aicpa.org/interestareas/peerreview>.

⁴²⁹ See above for more discussion of current QC requirements.

A positive externality inherent to the current audit market may exacerbate this risk. The services of an auditor provide benefits to a variety of investors and financial statement users, including current shareholders, potential shareholders, investors in other companies, creditors, and regulators, among others. However, auditors do not bargain with all of these parties. Rather, Sarbanes-Oxley requires that the audit committee be responsible for the appointment, compensation, and retention of the auditor.⁴³⁴ In practice, company management may also play a role through its influence over the audit committee.⁴³⁵ This creates a *de facto* principal-agent relationship between the company and the auditor. Moreover, some beneficiaries of the auditor's work (e.g., investors generally, who benefit from overall confidence in the quality of financial information provided to the market) may have no influence on the auditor at all. Economic theory suggests that, in the presence of positive externalities such as these, markets may undersupply goods or services.⁴³⁶ As a result, the positive externality in the audit market may create an additional risk that auditors may gather insufficient audit evidence to support their opinion or otherwise depart from applicable requirements.

A firm also faces its own management challenges in implementing its desired service, economic, and regulatory compliance objectives. Individual offices or personnel may have incentives that diverge from the firm's collective best interest. For example, some research suggests that certain partners or offices may be commercially dependent on particular clients and may be willing to take risks to retain those clients that the firm as a whole would not—a form of free riding on the firm's reputation and capacity to absorb

potential litigation costs.⁴³⁷ In addition, research suggests that an audit firm's QC system is essential to increase audit effort and audit quality because it aligns incentives of individual partners with those of the firm.⁴³⁸ Even if QC systems were able to align the incentives of individual offices and personnel to the firm's collective best interest, some research suggests that behavioral biases (e.g., confirmation bias, over-optimism, and anchoring bias) may lead offices or personnel to act in ways contrary to both their own self-interest and the firm's collective best interest.⁴³⁹ One commenter presented its recent unpublished survey research regarding challenges firms face when implementing changes to their QC systems. The commenter reported that challenges include obtaining buy-in and acceptance from staff as well as managing different perspectives from various offices.⁴⁴⁰

Some firms may manage these challenges by adopting centralized control practices that may have ambiguous impacts on their QC systems. For example, academic research suggests that firms carefully screen new partners to act in the best interest of the firm⁴⁴¹ and emphasize meeting engagement budgets—an easily monitored metric that ties directly to profitability.⁴⁴² One commenter asserted that audit firms' financial incentives to operate too lean undermine audit quality. Investors and other financial statement users may have trouble monitoring how firms incentivize, implement, and monitor compliance with applicable professional requirements. These monitoring challenges, as well as the lack of specificity in current PCAOB QC standards, give firms the flexibility to design, implement, and operate QC systems that may not fully meet the needs of investors and other financial statement users.

In the absence of sufficient market incentives to achieve an efficient allocation of audit services,⁴⁴³ regulatory intervention can introduce incentives that generate changes in behavior and impact audit quality.⁴⁴⁴ For example, economic research suggests that auditing standards play a role in determining the amount of effort an auditor exerts, which ultimately impacts audit quality.⁴⁴⁵ In addition, auditing standards can introduce incentives by providing a baseline against which an auditor manages legal liability.⁴⁴⁶ Auditing standards also provide a benchmark for regulatory inspections and enforcement actions that introduce incentives for firms to initiate changes that impact audit

⁴⁴³ An efficient allocation of resources occurs when total surplus is maximized. Total surplus is maximized when the good or service in question is supplied until the marginal benefit is equal to the marginal cost. See Mankiw, *Principles of Economics* 146–148.

⁴⁴⁴ See, e.g., W. Robert Knechel, *Do Auditing Standards Matter?*, 7 *Current Issues in Auditing* A1 (2013) (explaining that auditing standards send a message to auditors that it is inappropriate to intentionally under-audit, regardless of incentives). Note that QC standards are not auditing standards but that auditing standards are a closely related form of regulatory intervention. Also, academic research suggests that a positive association among standard setting, auditor effort, and audit quality depends on a number of factors. See, e.g., Pingyang Gao and Gaoqing Zhang, *Auditing Standards, Professional Judgment, and Audit Quality*, 94 *The Accounting Review* 201 (2019) (showing that auditing standards can help align auditor incentives with investor interests by compelling the auditor to exert more effort, which improves audit quality, but that auditing standards can weaken the auditor's incentive to acquire expertise, which reduces audit quality); Mark DeFond and Jieying Zhang, *A Review of Archival Auditing Research*, 58 *Journal of Accounting and Economics* 275 (2014) (concluding that the effectiveness of auditing standard setting is difficult to gauge since it involves broader consideration of the social welfare of all stakeholders).

⁴⁴⁵ See, e.g., Marleen Willekens and Dan A. Simunic, *Precision in Auditing Standards: Effects on Auditor and Director Liability and the Supply and Demand for Audit Services*, 37 *Accounting and Business Research* 217 (2007) (showing that decreasing the precision of auditing standards initially incentivizes auditors to produce higher audit quality by exerting more effort but that decreasing precision beyond a certain point leads auditors to decrease effort).

⁴⁴⁶ See, e.g., Ronald A. Dye, *Auditing Standards, Legal Liability, and Auditor Wealth*, 101 *Journal of Political Economy* 887 (1993) (showing that an auditor who intends to comply with standards typically prefers higher standards when the auditor's personal wealth is observable by potential litigants but prefers lower standards when the auditor's wealth is unobservable); Causholli and Knechel, *An Examination of the Credence* 631 (explaining that regulation and litigation play an important role in shaping the audit process and an auditor's behavior); Knechel, *Do Auditing Standards A1* (explaining that auditing standards can influence the likelihood and extent of under-auditing by providing a basis for auditor liability that is an increasing function of the extent to which auditor effort falls short of the standard-compliant level).

to use total surplus as a measure of society's economic well-being. . . Total surplus in a market is the total value to buyers of the goods, as measured by their willingness to pay, minus the total cost to sellers of providing those goods.”).

⁴³⁴ See section 301 of Sarbanes-Oxley, 15 U.S.C 78j–1.

⁴³⁵ See, e.g., Liesbeth Bruynseels and Eddy Cardinaels, *The Audit Committee: Management Watchdog or Personal Friend of the CEO?*, 89 *The Accounting Review* 113 (2014) (finding that social ties between management and the audit committee are present in 39% of the companies in their sample and “may reduce the quality of the audit committee's oversight”).

⁴³⁶ See, e.g., Mankiw, *Principles of Economics* 200, 201 (“In the presence of a positive externality, the social value of the good exceeds the private value. The optimal quantity is therefore larger than the equilibrium quantity . . . Positive externalities lead markets to produce a smaller quantity than is socially desirable.”).

⁴³⁷ See, e.g., Robert A. Prentice, *The Case of the Irrational Auditor: A Behavioral Insight into Securities Fraud Litigation*, 95 *Northwestern University Law Review* 133 (2000).

⁴³⁸ See, e.g., Daniel Aobdia, *The Economic Consequences of Audit Firms' Quality Control System Deficiencies*, 66 *Management Science* 2883 (2019).

⁴³⁹ See, e.g., Prentice, *The Case of the Irrational Auditor* 133, 162.

⁴⁴⁰ See Hayne, et al., *Managing Quality Control Systems*.

⁴⁴¹ See, e.g., C. J. McNair, *Proper Compromises: The Management Control Dilemma in Public Accounting and its Impact on Auditor Behavior*, 16 *Accounting, Organizations and Society* 635 (1991).

⁴⁴² See, e.g., Bernard Pierce and Breda Sweeney, *Cost–Quality Conflict in Audit Firms: An Empirical Investigation*, 13 *European Accounting Review* 415 (2004).

quality.⁴⁴⁷ Moreover, research suggests that PCAOB Part II inspection findings introduce strong incentives for firms to make changes necessary to remediate QC deficiencies in order to avoid public disclosure of the deficiencies.⁴⁴⁸

3. Current PCAOB QC Standards Do Not Directly Address Recent QC Developments

Developments in the auditing environment since the development of the current PCAOB QC standards by the AICPA and subsequent adoption of these standards on an interim basis by the Board are discussed above. In brief and as discussed above, the audit market has changed significantly since the AICPA developed the current PCAOB QC standards in 1997. At that time, the audit market was largely self-regulated by firms and QC inspections were performed through a peer review program. Since then, PCAOB oversight has led firms to address deficiencies identified during inspections, including making changes to their QC systems to remediate QC deficiencies.⁴⁴⁹ There have also been significant developments in the use of technology by firms in relation to QC activities and performing engagements. Some firm management and organizational structures have also evolved to include more focus on centralization and a globally consistent methodology. Some firms have strengthened their approaches to firm governance and leadership, incentive systems, and accountability. In addition, thought leadership in quality management has advanced,⁴⁵⁰ as have the QC standards adopted by other standard setters.

The current PCAOB QC standards are based on the higher-level principles described above and do not directly address the developments described in the previous paragraph. While research suggests that PCAOB oversight is

associated with higher audit quality,⁴⁵¹ the current PCAOB QC standards were not written with a view to inspection and enforcement by a regulator. As a result, the current PCAOB QC standards yield a regulatory baseline that is not rigorous enough to sufficiently support the Board's ability to address audit performance deficiencies through PCAOB inspection and enforcement activities related to firms' QC systems. For example, some firms have added external parties to oversight roles as described above, but current PCAOB QC standards contain limited references to firm governance and leadership. At the same time, the current PCAOB QC standards do not provide sufficiently specific requirements to directly incentivize firms and individuals to establish and implement QC policies and procedures that achieve the reasonable assurance objective as evidenced by the prevalence of audit performance deficiencies.

4. Prevalence of Audit Performance Deficiencies

The three proxies for the level of compliance with applicable professional standards discussed above—*i.e.*, Part I.A deficiencies, QC deficiencies related to audit performance, and deficiencies arising during inspections of broker-dealer engagements—as well as the recent PCAOB enforcement actions discussed above suggest that some firms' QC systems are not providing reasonable assurance as required under current PCAOB QC standards.⁴⁵² To be sure, this analysis of PCAOB inspection activities does suggest that some improvements in audit performance have followed from remedial changes firms have made to their QC systems⁴⁵³ and that some firms have already reduced the number of QC deficiencies related to management of their audit practice.⁴⁵⁴ However, the Board continues to observe high rates of audit performance deficiencies⁴⁵⁵ and believes that a new QC standard will address these audit performance deficiencies because the new standard

will incentivize firms to design, implement, and operate effective QC systems.

5. How the Requirements Address the Need

The requirements provide substantial additional direction to firms regarding the design, implementation, and operation of their QC systems that the Board believes address the need for standard-setting. Three overarching features of the requirements help address the problem. The first feature pertains to the mandate for a more integrated, proactive, and risk-based QC system. The second pertains to the enhancements to accountability within the firm to achieve the reasonable assurance objective. The third pertains to more precise language and more prescriptive requirements in several key areas.

Regarding the first feature, the new risk assessment process, coupled with a detailed monitoring and remediation process, form a feedback loop designed to foster a proactive approach to QC that drives continuous improvement. For example, the risk assessment process requires the firm to obtain an understanding of the conditions, events, and activities that may adversely affect the achievement of its quality objectives; identify and assess quality risks; and then design and implement quality responses. The monitoring and remediation process will help the firm evaluate whether the QC system is working effectively in practice. This more proactive approach to QC should help address the positive externality problem in the audit market by leading firms to implement QC systems that more consistently satisfy the interests of all beneficiaries of the audit. Additionally, as discussed above, information asymmetry may cause investors and other financial statement users not to have sufficient information to understand whether their issuer's audit firm has an effective QC system that consistently produces high-quality audits, and investors and other financial statement users may not have a sufficient voice in the financial reporting ecosystem to be able to demand or incentivize audit firms to implement one. Requiring the auditor to implement a robust QC system substitutes a compliance incentive for the insufficient market incentive.

Regarding the second feature, the Board believes QC 1000 will improve accountability within the firm to achieve the reasonable assurance objective. Several of the requirements that improve accountability within the firm address the positive externality

⁴⁴⁷ See, e.g., Aobdia, *The Impact of the PCAOB Individual 53* (finding that firms take corrective action on engagements with PCAOB Part I inspection findings and the effects spillover to non-inspected engagements); Phillip T. Lamoreaux, Michael Mowchan, and Wei Zhang, *Does Public Company Accounting Oversight Board Regulatory Enforcement Deter Low-Quality Audits?*, 98 *The Accounting Review* 335 (2023) (finding that large audit firm offices improve audit quality following enforcement naming another office within their firm while small firm offices improve following enforcement of local small firm competitors).

⁴⁴⁸ See, e.g., Aobdia, *The Economic Consequences* 2883.

⁴⁴⁹ See discussion on the developments in firms' QC policies and procedures within the baseline discussion above.

⁴⁵⁰ See, e.g., COSO, ISO 9000, and the audit firm governance codes of the UK Financial Reporting Council and Japan Financial Services Agency.

⁴⁵¹ See, e.g., Albert L. Nagy, *PCAOB Quality Control Inspection Reports and Auditor Reputation*, 33 *Auditing: A Journal of Practice & Theory* 87 (2014) (concluding that audit firms lose market share following public disclosure of PCAOB Part II inspection findings, suggesting that disclosure provides a credible signal of auditor quality). The results from this study that suggests a positive association between PCAOB oversight and audit quality does not necessarily mean that PCAOB oversight causes higher audit quality.

⁴⁵² See Background discussion above for more discussion of current regulatory requirements.

⁴⁵³ This point is discussed more fully in below.

⁴⁵⁴ See Figure 5 above.

⁴⁵⁵ See Figures 1 and 3 above.

problem directly by leading firms to implement QC systems that more consistently satisfy the interests of all beneficiaries of the audit. For example, QC 1000 requires the firm to document and assign roles and responsibilities; communicate information related to the monitoring and remediation process to firm personnel to enable them to take timely action in accordance with their responsibilities; and establish a quality objective to incentivize individuals to fulfill their assigned responsibilities, through means such as performance evaluations and compensation. Leadership will also be accountable for the design, implementation, and operation of the firm's QC system, including through means such as their performance evaluation and compensation, and the firm will be required to establish a quality objective that leadership communicate and promote the firm's role in protecting the interests of investors and the public interest. The requirements that improve accountability within the firm will help address the information asymmetry problem by requiring the firm's QC system to operate over any public reporting regarding firm or engagement metrics that the firm provides.⁴⁵⁶ Overall, this second feature reinforces the first through an additional incentive that is personal to responsible individuals within the firm and reinforces the general incentives for the firm to comply with the standard.

Regarding the third feature, while the requirements provide substantial additional guidance to firms regarding the design, implementation, and operation of their QC systems, QC 1000 also provides more precise and prescriptive requirements that will enhance the Board's ability to inspect and enforce and incentivize firms to design, implement, and operate effective QC systems. For example, QC 1000 includes more unconditional responsibilities than current PCAOB QC standards and specifies precise conditions under which a firm must design, implement, and operate an effective QC system. Together with the features described above—*i.e.*, a more integrated, proactive, and risk-based QC system and enhanced accountability within the firm to achieve the reasonable assurance objective—these features establish a regulatory baseline that more directly incentivizes firms and individuals to comply in order to avoid enforcement.

⁴⁵⁶ See PCAOB Rel. No. 2024–002 and PCAOB Rel. No. 2024–003.

Economic Impacts

This section discusses the expected benefits and costs, and the potential unintended consequences, that may result from the requirements. The expected impacts of several key provisions are highlighted. These provisions relate to:

- Scaled applicability;
- In-process monitoring activities;
- Firm governance structure;
- The automated independence process;
- Complaints and allegations policies and procedures;
- Reporting the annual QC system evaluation;
- Certification of the annual QC system evaluation;
- Responding to engagement deficiencies identified after issuance of the audit report; and
- SECPS requirements.

While the analysis of economic impacts is largely qualitative in nature due to data limitations, the analysis does, in part, use PCAOB inspections data to help evaluate the expected benefits. Technical details regarding the quantitative analysis of the expected benefits are included in a separate staff white paper.⁴⁵⁷

The economic impacts of the requirements will arise out of changes firms will make to their QC systems that they would not otherwise make but for the requirements. As discussed above, the Board expects that, absent the requirements, many firms would continue to make changes to their QC systems in response to evolving audit market conditions, advances in technology, PCAOB oversight activity, internal monitoring, and the actions of other standard setters. This attenuates both the benefits and the costs attributable to the requirements.

1. Benefits

The expected benefits of the requirements are described using four complementary views: (1) the benefits of quality management frameworks generally; (2) the direct benefits of the requirements in the form of improved compliance with applicable professional and legal requirements; (3) the indirect benefits of the requirements in the form of improved financial reporting quality and capital market efficiency; and (4) the benefits of key provisions.

⁴⁵⁷ See PCAOB, *Staff White Paper, The Impact of Quality Control System Remediation on Audit Performance and Financial Reporting Quality* (Nov. 18, 2022), (“QC White Paper”), available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/rulemaking/docket046/qc-staff-white-paper-november-2022.pdf?sfvrsn=dcb22504_4.

a. Benefits of Related Frameworks

QC 1000 bears resemblance to existing quality management and enterprise risk management frameworks (*e.g.*, ISO 9000 and COSO). These frameworks share several features in common with QC 1000, including embedding risk in decision making, proactive involvement of leadership, clearly defined objectives, objective-oriented processes, monitoring, and remediation. Using a variety of proxies (*e.g.*, market reaction), academic research has found that these frameworks improve company performance.⁴⁵⁸ In particular, researchers have found that the COSO framework—the closest antecedent to QC 1000—effectively improves financial reporting.⁴⁵⁹ Similarly, research finds that markets penalize public companies with weaker internal control systems and reward the remediation of those weaknesses.⁴⁶⁰ While differences between QC 1000 and existing frameworks as well as differences between audit firms and other companies may limit the relevance of this research to some extent, this research suggests that QC 1000 may help firms design, implement, and operate more effective QC systems.

b. Improved Compliance With Applicable Professional and Legal Requirements

The Board expects the requirements will benefit investors and other financial statement users by improving compliance with applicable professional and legal requirements via a more detailed QC standard. As described above, the requirements are expected to achieve this through three principal mechanisms. First, they explicitly connect the components of the QC system into an integrated cycle of risk assessment, performance monitoring, and remediation. Second, several of the new requirements will support the effectiveness of QC systems by

⁴⁵⁸ See, *e.g.*, Iñaki Heras-Saizarbitoria and Olivier Boiral, *ISO 9001 and ISO 14001: Towards a Research Agenda on Management System Standards*, 15 *International Journal of Management Reviews* 47 (2013); Robert E. Hoyt and Andre P. Liebenberg, *The Value of Enterprise Risk Management*, 78 *Journal of Risk and Insurance* 795 (2011).

⁴⁵⁹ See, *e.g.*, Hanwen Chen, Wang Dong, Hongling Han, and Nan Zhou, *A Comprehensive and Quantitative Internal Control Index: Construction, Validation, and Impact*, 49 *Review of Quantitative Finance and Accounting* 337 (2017); Ifeoma Udeh, *Observed Effectiveness of the COSO 2013 Framework*, 16 *Journal of Accounting & Organizational Change* 31 (2020).

⁴⁶⁰ See, *e.g.*, Hollis Ashbaugh-Skaife, Daniel W. Collins, William R. Kinney, Jr., and Ryan Lafond, *The Effect of SOX Internal Control Deficiencies on Firm Risk and Cost of Equity*, 47 *Journal of Accounting Research* 1 (2009).

emphasizing accountability to the reasonable assurance objective. Third, more precise and prescriptive requirements will enhance the Board's ability to inspect and enforce. Broker-dealer engagements and issuer audits performed by firms other than U.S. GNFs may see more improvement because they appear to have more room for improvement on average. However, the recent uptick in deficiencies for U.S. GNFs suggests that QC 1000 will also be a valuable resource for these firms to address those deficiencies and, thus, further protect investors.

Some commenters described how a risk-based QC standard would improve audit quality. However, one commenter argued that the requirements are too risk-based (e.g., they could result in too little change at the larger firms) and suggested an even stronger prescriptive approach to certain aspects of the standard (e.g., training and supervision). The Board believes the standard reflects a balanced approach that includes prescriptive requirements where appropriate.

PCAOB staff analysis of PCAOB inspections data supports the view that more effective QC policies and procedures will lead to improved compliance with applicable professional and legal requirements. Staff examined the historical association between satisfactory remediation of QC deficiencies and subsequent Part I.A deficiencies for triennial firms. Satisfactory remediation of a QC deficiency reflects substantial good-faith progress toward achieving a quality control objective.⁴⁶¹ As such, an association between historical satisfactory remediation efforts and a subsequent decrease in Part I.A deficiencies would suggest that more effective QC policies and procedures lead to improved compliance with applicable professional and legal requirements. After controlling for auditor and issuer characteristics that may also drive Part I.A deficiencies using standard statistical techniques, the staff analysis indicates that, on average, satisfactory remediation is associated with reduced likelihood of subsequent Part I.A deficiencies. This suggests that more effective QC policies and procedures may lead to improved compliance with applicable professional and legal requirements.⁴⁶² One commenter reported observing that satisfactory remediation of QC

deficiencies results in fewer audit failures and asserted that this was in line with certain key findings of the staff analysis.

The staff analysis is subject to several important caveats. First, remedial actions typically target specific aspects of a firm's QC system. By contrast, implementation of QC 1000 may require a broader set of changes. Second, due to the transformational nature of QC 1000, the changes firms will make to their QC systems could be substantially different from firms' historical satisfactory remedial actions. Third, U.S. GNFs were intentionally excluded from the analysis, potentially limiting its applicability to the U.S. GNFs. However, though association does not imply causation, the historical association between the number of QC deficiencies related to U.S. GNFs' management of their audit practice⁴⁶³ and U.S. GNFs' compliance with applicable professional standards⁴⁶⁴ suggests that, even among the U.S. GNFs, more effective QC systems could lead to improved compliance with applicable professional and legal requirements.⁴⁶⁵ Overall, the Board expects the association between satisfactory remediation and subsequent Part I.A deficiencies among triennial firms more likely understates the impact of QC 1000 due to its transformational nature.

Observations from PCAOB inspections and academic research also suggest that the requirements may improve compliance with applicable professional and legal requirements. PCAOB inspectors have observed that root cause analyses, effective design and implementation of remedial actions, and appropriate governance practices related to leadership's tone can drive audit quality,⁴⁶⁶ and one academic study reports that, as perceptions of the strength of the QC system increase, the likelihood of "reduced audit quality

behaviors" decreases.⁴⁶⁷ These findings likewise support the view that the requirements, which place greater emphasis on root cause analysis, remediation, and governance practices, if successfully implemented, will lead to improved compliance with applicable professional and legal requirements.

c. Improved Financial Reporting Quality and Capital Market efficiency

Academic research provides evidence that compliance with auditing standards is positively associated with proxies for financial reporting quality.⁴⁶⁸ Research also finds a positive association between firms' successful remediation of QC deficiencies—a proxy for adopting effective QC system practices—and the financial reporting quality of their issuer clients.⁴⁶⁹ PCAOB staff analysis also provides some evidence that successful remediation may be associated with improved financial reporting quality.⁴⁷⁰ The fact that the results from each of these studies that suggest a positive association with financial reporting quality does not necessarily mean that auditing standards or remediation of deficiencies cause better financial reporting quality.

Investors and other financial statement users may benefit from improved issuer financial reporting quality because it helps solve information asymmetries and agency problems inherent to capital markets. Economic theory suggests that investors face a separation-of-ownership-and-control problem whereby issuer management may misappropriate investors' capital.⁴⁷¹ Relevant and accurate financial reporting can alleviate these problems by providing investors and other financial statement users with more accurate information regarding the financial position and operating results of companies. Investors may use this information to improve the efficiency of their capital

⁴⁶⁷ See, e.g., Charles F. Malone and Robin W. Roberts, *Factors Associated with the Incidence of Reduced Audit Quality Behaviors*, 15 *Auditing: A Journal of Practice & Theory* 49 (1996).

⁴⁶⁸ See, e.g., Daniel Aobdia, *Do Practitioner Assessments Agree with Academic Proxies for Audit Quality? Evidence from PCAOB and Internal Inspections*, 67 *Journal of Accounting and Economics* 144 (2019); Katherine A. Gunny and Tracey Chunqi Zhang, *PCAOB Inspection Reports and Audit Quality*, 32 *Journal of Accounting and Public Policy* 136 (2013).

⁴⁶⁹ See, e.g., Aobdia, *The Economic Consequences* 2883.

⁴⁷⁰ See QC White Paper.

⁴⁷¹ See, e.g., Michael C. Jensen and William H. Meckling, *Theory of the Firm: Managerial Behavior, Agency Costs and Ownership Structure*, 3 *Journal of Financial Economics* 305 (1976); Adolf Augustus Berle and Gardiner Coit Means, *The Modern Corporation and Private Property* (1991).

⁴⁶¹ See *Staff Guidance Concerning the Remediation Process* (Nov. 18, 2013), available at https://pcaobus.org/Inspections/Pages/Remediation_Process.aspx.

⁴⁶² For additional details, including definitions of all control variables, see QC White Paper.

⁴⁶³ See Figure 5 above.

⁴⁶⁴ See Figures 1 and 3 above.

⁴⁶⁵ Several nuances of smaller firms' QC systems and the PCAOB inspections process may explain the absence of such an association for these firms. First, although there is a downward trend in QC deficiencies related to management of the audit practice (Figure 5 above), smaller firms' QC systems may be deficient in certain important respects that render them less effective overall. Second, the roughly increasing trend in QC deficiencies related to audit performance for the smallest firms (Figure 3 above) may be driven in part by deficiencies in the application of new auditing requirements by these firms. Third, the inspection approach to QC assessments for the smaller firms is simplified and does not lend itself to such a correlation analysis.

⁴⁶⁶ See, e.g., 2018 Inspection Observations Preview

allocation decisions (e.g., investors may more accurately identify companies with the strongest prospects for generating future risk-adjusted returns and allocate their capital accordingly). Investors may also perceive less risk in capital markets generally, leading to an increase in the supply of capital. An increase in the supply of capital could increase capital formation while also reducing the cost of capital to companies.⁴⁷² While some uncertainty remains regarding the economic impacts of financial reporting,⁴⁷³ empirical academic research has affirmed this basic premise under certain conditions.⁴⁷⁴ Moreover, some studies have identified a direct association between auditors' compliance with PCAOB standards and capital market efficiency.⁴⁷⁵

The requirements may also lead to improved compliance with applicable professional and legal requirements on broker-dealer audit engagements and, in turn, improved financial reporting quality and investor protection. An

auditor's work on these engagements, if appropriately performed, should make it more likely that a broker-dealer will maintain appropriate controls over compliance and less likely that there will be material reporting errors. The auditor's work also has the potential to make it more difficult for broker-dealers to engage in fraud and other misconduct. Improved broker-dealer financial reporting quality also gives industry overseers, such as the SEC and FINRA, as well as other users of broker-dealer financial information, such as the Securities Investor Protection Corporation, more accurate information relevant to a broker-dealer's financial condition, its ability to continue as a going concern, and its handling of customer securities and cash. This, in turn, enhances the ability of these organizations to carry out their responsibilities in ways that protect investors. Compliance with applicable professional and legal requirements may also contribute to the early identification or prevention of broker-dealer failures. Failures of large broker-dealers can have a negative impact on the stability and liquidity of financial markets, and failures caused by misconduct may damage investor confidence. A reduction in such failures could help improve the strength and safety of the financial system.

d. Benefits of Key Provisions

i. Scaled Applicability

QC 1000 will require that a firm implement and operate an effective QC system at all times when the firm is required to comply with applicable professional and legal requirements with respect to any of the firm's engagements, and thereafter through the next September 30.⁴⁷⁶ The discussion above provides further information on this provision. As of June 30, 2023, up to 60% of firms may not meet this criterion but will be required to design a QC system in compliance with QC 1000.⁴⁷⁷ Because registering with the

PCAOB enables a firm to issue audit reports or play a substantial role on audits performed under PCAOB standards for issuers and broker-dealers, and because investors and companies considering engaging the firm could reasonably expect that any firm that could pursue such an engagement would already have a PCAOB-compliant QC system designed and ready for implementation and operation, the Board believes that imposing a design requirement on all registered firms promotes its mission of protecting investors and promoting the public interest. The Board also believes that designing the QC system will better position these firms to accept and perform engagements in compliance with applicable professional and legal requirements to the extent that the firm will have a PCAOB-compliant QC system ready for implementation and operation.

ii. In-Process Monitoring Activities

QC 1000 will require firms that issued audit reports with respect to more than 100 issuers during the prior calendar year to monitor in-process engagements and will require all other firms to consider monitoring in-process engagements.⁴⁷⁸ The discussion above provides further information on this provision. Monitoring in-process engagements can help firms detect and prevent engagement deficiencies before the engagement report is issued, resulting in a more proactive and preventive monitoring approach that has the potential to benefit investors through improved audit quality. The benefits will depend on the extent to which firms already have in-process monitoring activities in place. Information gathered through PCAOB inspection activities indicates that 11 out of 14 annually inspected firms perform some in-process engagement monitoring activities.

iii. Firm Governance Structure

QC 1000 will require firms that issued audit reports with respect to more than 100 issuers during the prior calendar year to incorporate into their governance structure an external oversight function for the QC system composed of one or more persons who are not principals or employees of the firm and do not otherwise have a commercial, familial, or other relationship with the firm that would interfere with the exercise of

Act (e.g., offerings under Regulation A, Regulation D, or Regulation Crowdfunding), pursuant to a contractual obligation such as a loan covenant, or on an entirely voluntary basis.

⁴⁷⁸ See QC 1000.63.

⁴⁷² See, e.g., Richard Lambert, Christian Leuz, and Robert E. Verrecchia, *Accounting Information, Disclosure, and the Cost of Capital*, 45 *Journal of Accounting Research* 385, 387 (2007) (discussing how increasing the quality of mandated disclosures should in general move the cost of capital to the risk-free rate for all firms in the economy); William Robert Scott and Patricia C. O'Brien, *Financial Accounting Theory* (2003), 412 (explaining that regulation is intended to improve the operation of capital markets by enhancing public confidence in their fairness).

⁴⁷³ See, e.g., Christian Leuz and Peter D. Wysocki, *The Economics of Disclosure and Financial Reporting Regulation: Evidence and Suggestions for Future Research*, 54 *Journal of Accounting Research* 525 (2016) (explaining the relative rarity of evidence on causal effects of disclosure and reporting regulation); Matthias Breuer, Christian Leuz, and Steven Vanhaverbeke, *Mandated Financial Reporting and Corporate Innovation*, No. w26291, National Bureau of Economic Research (2020), at 41 (reporting evidence consistent with the notion that mandatory reporting deters firms' incentives to innovate and generate proprietary know-how because of concerns about the loss of proprietary information).

⁴⁷⁴ See, e.g., Christian Leuz and Robert E. Verrecchia, *The Economic Consequences of Increased Disclosure*, 38 *Journal of Accounting Research* 91 (2000) (finding that German companies that elect to commit to International Accounting Standards or U.S. GAAP exhibit lower percentage bid-ask spreads and higher share turnover than firms using German GAAP); Utpal Bhattacharya, Hazem Daouk, and Michael Welker, *The World Price of Earnings Opacity*, 78 *The Accounting Review* 641 (2003) (finding that an increase in overall earnings opacity in a country is linked to an economically significant increase in the cost of equity and an economically significant decrease in trading in the stock market of that country based on financial statements from 34 countries for the period 1984–1998). Because U.S. institutions differ from other countries and the studies pre-date Sarbanes-Oxley, the results may not be directly relevant to all PCAOB-registered firms.

⁴⁷⁵ See, e.g., Nemit Shroff, *Real Effects of PCAOB International Inspections*, 95 *The Accounting Review* 399 (2020).

⁴⁷⁶ See QC 1000.07.

⁴⁷⁷ The 60% reported here is based on Form 2 reporting as of June 30, 2023, and reflects registered firms that reported they had not issued an audit report for an audit of an issuer or broker-dealer or played a substantial role in such an engagement during the preceding 12 months. As noted above, approximately 51% of firms have not performed an engagement under PCAOB standards for an issuer or broker-dealer in the past five years. The PCAOB does not collect information about whether registered firms perform engagements under PCAOB standards other than for issuers and broker-dealers. Firms may be engaged, for example, in connection with the audit of a reporting company that does not meet the Sarbanes-Oxley definition of "issuer" described in footnote 2 above, in connection with certain offerings of securities that are exempt from registration under the Securities

independent judgment with regard to matters related to the QC system (*i.e.*, EQCF).⁴⁷⁹ The final standard specifies a baseline requirement that the EQCF's responsibilities should include, at a minimum, evaluating the significant judgments made and the related conclusions reached by the firm when evaluating and reporting on the effectiveness of its QC system. The discussion above provides further information on this provision. Such an oversight function could reduce negative impacts of commercial considerations on decision making by firms about their QC system and thereby improve incentives to implement QC systems that more fully meet the interests of investors and other financial statement users. Some academic research finds that the level of board of directors independence is associated with certain benefits, such as improved operating performance and company value, which implies independent oversight in a firm's governance structure could potentially improve the quality of audit services provided by the firm.⁴⁸⁰

iv. The Automated Independence Process

QC 1000 will require firms that issued audit reports with respect to more than 100 issuers during the prior calendar year to automate the process to identify investments in securities that might impair the independence of the firm or firm personnel that are managerial employees or partners, shareholders, members, or other principals.⁴⁸¹ The discussion above provides further information on this provision. Automating this process should help firms more effectively and efficiently identify such investments. The automated process could also indirectly improve compliance with other relevant independence requirements. For example, automating this process may lead firms to maintain and make available the list of restricted entities more efficiently and effectively.

v. Complaints and Allegations Policies and Procedures

QC 1000 will require firms to design, implement, and maintain policies and procedures that address processes and responsibilities for receiving, investigating, and addressing complaints and allegations and include protecting persons making complaints and allegations from retaliation.⁴⁸² Firms that issued audit reports with respect to more than 100 issuers during the prior calendar year will be required to include confidentiality protections in their policies and procedures. The discussion above provides further information on this provision. Overall, the Board expects the policies and procedure regarding complaints and allegations will help reduce information asymmetry within the firm by alerting responsible individuals to instances of non-compliance of which they may otherwise be unaware. Some academic research suggests that the complaints and allegations provisions will increase the likelihood that individuals will submit complaints and allegations related to potential non-compliance. For example, one survey of public company auditors finds that (1) greater protection of individual identity and (2) trust that the firm would investigate and act on a report are both positively associated with intention to report non-compliance with auditing standards.⁴⁸³ A survey of accounting students finds that a weaker threat of retaliation is positively associated with the propensity to submit a complaint.⁴⁸⁴ The Board acknowledges that some experimental research finds that explicit protections may unintentionally deter internal complaints and allegations because the protections signal to potential persons making complaints that retaliation is a risk.⁴⁸⁵ However, overall, the Board expects the complaints and allegations provisions will benefit investors by reducing non-compliance with auditing standards and, thus, improving audit quality.

⁴⁷⁹ See QC 1000.28.

⁴⁸⁰ See, e.g., Anzhela Knyazeva, Diana Knyazeva, and Ronald W. Masulis, *The Supply of Corporate Directors and Board Independence*, 26 *The Review of Financial Studies* 1561 (2013). Other academic research indicates that a tradeoff of more independent board of directors may be less efficient monitoring by directors. See, e.g., Praveen Kumar and K. Sivaramakrishnan, *Who Monitors the Monitor? The Effect of Board Independence on Executive Compensation and Firm Value*, 21 *The Review of Financial Studies* 1371 (2008).

⁴⁸¹ See QC 1000.34a.

⁴⁸² See QC 1000.29.

⁴⁸³ See Mary B. Curtis and Eileen Z. Taylor, *Whistleblowing in Public Accounting: Influence of Identity Disclosure, Situational Context, and Personal Characteristics*, 9 *Accounting and the Public Interest* 191 (2009).

⁴⁸⁴ See Gregory Liyanarachchi and Chris Newdick, *The Impact of Moral Reasoning and Retaliation on Whistle-Blowing*, 89 *Journal of Business Ethics* 37 (2009).

⁴⁸⁵ See James Wainberg and Stephen Perreault, *Whistleblowing in Audit Firms: Do Explicit Protections from Retaliation Activate Implicit Threats of Reprisal?*, 28 *Behavioral Research in Accounting* 83 (2016).

vi. Reporting the Annual QC System Evaluation

QC 1000 will require firms to report to the PCAOB about the annual evaluation of their QC system.⁴⁸⁶ The discussion above provides further information on this provision. This requirement will help the Board obtain more timely, structured, and consistent information regarding the effectiveness of firms' QC systems relative to what could be gathered through the inspections process, especially for the triennial firms. The Board will use this information to support its oversight activities (e.g., to select firms, audits, or focus areas for review). Reporting to the PCAOB will also improve incentives within a firm to design, implement, and operate an effective QC system.

vii. Certification of the Annual QC System Evaluation

QC 1000 will require certain individuals in firms' leadership to certify the annual evaluation of their firm's QC system.⁴⁸⁷ The discussion above provides further information on this provision. This requirement will help address the positive externality problem in the audit market by creating greater accountability within firm leadership to implement an effective QC system. As noted in the proposal, PCAOB staff reviewed academic literature on the impacts of CEO and CFO certification requirements in the U.S. and engagement partner signature requirements in the United Kingdom and found both supportive and unsupportive findings.⁴⁸⁸ One commenter noted academic research that has found there is little, if any, effect of CEO and CFO certifications

⁴⁸⁶ See QC 1000.79.

⁴⁸⁷ See QC 1000.14d. and .15b.

⁴⁸⁸ See, e.g., Daniel A. Cohen, Aiysha Dey, and Thomas Z. Lys, *Corporate Governance Reform and Executive Incentive: Implications for Investments and Risk Taking*, 30 *Contemporary Accounting Research* 1298 (2013) (finding that their sample of firms significantly reduced investments in risky projects in the period following SOX); Hsihui Chang, Jengfang Chen, Woody M. Liao, and Birendra K. Mishra, *CEOs'/CFOs' Swearing by the Numbers: Does it Impact Share Price of the Firm?*, 81 *The Accounting Review* 1, 22 (2006) (concluding that the SEC order requiring filing of sworn statements by CEOs and CFOs had a positive effect on the market value of certifying firms); Jeffrey R. Cohen, Colleen Hayes, Ganesh Krishnamoorthy, Gary S. Monroe, and Arnold M. Wright, *The Effectiveness of SOX Regulation: An Interview Study of Corporate Directors*, 25 *Behavioral Research in Accounting* 61 (2013) (discussing that CEO certification was viewed as having led to heightened ownership and diligence on the part of decision agents throughout the financial reporting decision hierarchy but was also identified as a source of the costly resource-intensive reaction to Sarbanes-Oxley).

required under Sarbanes-Oxley.⁴⁸⁹ Citing academic literature on accountability frameworks, the same commenter noted that imposition of accountability is largely positive⁴⁹⁰ but that the increased accountability that would result from the certification requirement could have negative consequences.⁴⁹¹ As discussed below, the Board acknowledges that increased accountability could lead to potential unintended consequences. However, the Board continues to believe that the certification requirement will benefit investors by increasing discipline in the

⁴⁸⁹ See, e.g., Paul A. Griffin and David H. Lont, *Taking the Oath: Investor Response to SEC Certification Under Sarbanes-Oxley*, 1 Journal of Contemporary Accounting & Economics 27 (2005); Gerald J. Lobo and Jian Zhou, *Did Conservatism in Financial Reporting Increase after the Sarbanes-Oxley Act? Initial Evidence*, 20 Accounting Horizons 57 (2006); Utpal Bhattacharya, Peter Groznik, and Bruce Haslem, *Is CEO Certification of Earnings Numbers Value-Relevant?*, 14 Journal of Empirical Finance 611 (2007).

⁴⁹⁰ See, e.g., Andrew Quinn and Barry R. Schlenker, *Can Accountability Produce Independence? Goals as Determinants of the Impact of Accountability on Conformity*, 28 Personality and Social Psychology Bulletin 472 (2002); Virginia R. Stewart, Deirdre G. Snyder, and Chia-Yu Kou, *We Hold Ourselves Accountable: A Relational View of Team Accountability*, 183 Journal of Business Ethics 691 (2023); Angela T. Hall, Michael G. Bowen, Gerald R. Ferris, M. Todd Royle, Dale E. Fitzgibbons, *The Accountability Lens: A New Way to View Management Issues*, 50 Business Horizons 405 (2007); Marko Pitesa and Stefan Thau, *Masters of the Universe: How Power and Accountability Influence Self-Serving Decisions under Moral Hazard*, 98 Journal of Applied Psychology 550 (2013); Constantine Sedikides, Deletha Hardin, Kenneth Herbst, and Gregory Dardis, *Accountability as a Deterrent to Self-Enhancement: The Search for Mechanisms*, 83 Journal of Personality & Social Psychology 592 (2002).

⁴⁹¹ See, e.g., Jennifer J. Dose and Richard J. Klimoski, *Doing the Right Thing in the Workplace: Responsibility in the Face of Accountability*, 8 Employee Responsibilities & Rights Journal 35 (1995); Jennifer S. Lerner and Philip E. Tetlock, *Accounting for the Effects of Accountability*, 125 Psychological Bulletin 255 (1999); Randall A. Gordon, Richard M. Rozelle, and James C. Baxter, *The Effect of Applicant Age, Job Level, and Accountability on Perceptions of Female Job Applicants*, 123 Journal of Psychology 59 (1989); Philip E. Tetlock, *The Impact of Accountability on Judgment and Choice: Toward a Social Contingency Model*, 25 Advances in Experimental Social Psychology 331 (1992); Angela T. Hall, Dwight D. Frink, and M. Ronald Buckley, *An Accountability Account: A Review and Synthesis of the Theoretical and Empirical Research on Felt Accountability*, 38 Journal of Organizational Behavior 204 (2017); Sheldon Adelberg and Daniel C. Batson, *Accountability and Helping: When Needs Exceed Resources*, 36 Journal of Personality and Social Psychology 343 (1978); Mark E. Peecher, Ira Solomon, and Ken T. Trotman, *An Accountability Framework for Financial Statement Auditors and Related Research Questions*, 38 Accounting, Organizations and Society 596 (2013); Angela T. Hall, M. Todd Royle, Robert A. Brymer, Pamela L. Perrewé, Gerald R. Ferris and Wayne A. Hochwarter, *Relationships Between Felt Accountability as a Stressor and Strain Reaction: The Neutralizing Role of Autonomy Across Two Studies*, 11 Journal of Occupational Health Psychology 87 (2006).

evaluation process and reinforcing the accountability of the certifying individuals.

viii. Responding to Engagement Deficiencies Identified After Issuance of the Audit Report

The amendments to AS 2901, *Consideration of Omitted Procedures After the Report Date*, include: (1) addressing engagement deficiencies in addition to omitted procedures and (2) including the ICFR audit within its scope. Relatedly, the amendments to AT No. 1 and AT No. 2 mirror the amendments to AS 2901. The discussion above provides further information on this provision. The Board expects these amendments will lead auditors to perform additional procedures to obtain sufficient appropriate evidence or take additional action to prevent future reliance on insufficiently supported audit opinions (or review reports in the case of review engagements) that are being relied on. In such cases, PCAOB standards will require firms to advise their client to make appropriate disclosure of the newly discovered facts and their impact on the financial statements (or examination or review reports in the case of attestation engagements) to persons who are known to be currently relying or who are likely to rely on the financial statements and the related auditor's report (or review report in the case of a review engagement). Academic research on ICFR suggests that such disclosures will be valuable to capital market participants with improvements in company performance and financial reporting.⁴⁹²

ix. SECPS Requirements

The requirements will refine, integrate into QC 1000, and extend to all firms the SECPS member requirements currently required under PCAOB Rule 3400T. Based on current registration data, approximately 13% of PCAOB-registered firms are already subject to these requirements under PCAOB Rule 3400T. The discussion above provides an overview of these requirements. The Board expects that this feature of the rulemaking will benefit investors by enhancing audit quality through improved compliance with SEC and PCAOB independence rules on engagements performed by firms not already subject to these requirements under PCAOB Rule 3400T.

⁴⁹² See discussion on economic impacts above and the research cited therein.

2. Costs

The Board expects the requirements will result in additional direct and indirect costs to auditors and, potentially, indirect costs to the companies that they audit. The extent of these costs will depend on the degree to which firms otherwise have QC systems in place designed to comply with other QC standards and the specific policies and procedures adopted by the firm. The information presented above suggests that U.S. GNFs commit hundreds of partner and non-partner FTEs to their QC systems, including, individually, each of the major QC system components specified in ISQM 1. Resources are particularly utilized in the areas of independence, ethics, and resources. As discussed above, the Board believes most firms are subject to other QC standards. In designing, implementing, and operating their QC systems, firms that are subject to both PCAOB standards and other QC standards can leverage the investments they make to comply with the requirements of the other standards. Therefore, the Board expects that a portion of the overall costs of designing, implementing, and operating policies and procedures to comply with QC 1000 have been or will be incurred by most firms regardless of whether QC 1000 is adopted. As a consequence, for most firms, the Board expects the costs discussed below will derive primarily from the provisions in QC 1000 that go beyond the requirements of other QC standards.

Several commenters noted there will be costs and challenges to implement and operate features of QC 1000 that are incremental to the systems firms have established to comply with other QC standards. One commenter said that the need to accommodate nuances among different standards results in firms maintaining different methodologies, practices, and procedures that puts pressure on limited firm resources. Several commenters asserted that firms that audit between 100 and 500 issuers will be significantly impacted by costs associated with some or all of QC 1000's incremental requirements for firms that issue audit reports for more than 100 issuers, and some of the commenters noted resource differences between GNFs and annually inspected NAFs. Since QC systems are resource-intensive, the efforts required to respond to the additional provisions in QC 1000 or to otherwise adapt the QC system to the auditing environment for issuers and SEC-registered broker-dealers could be significant.

While the PCAOB lacks data to quantify the costs that could result from QC 1000, some studies have estimated costs associated with ICFR under Sarbanes-Oxley section 404.⁴⁹³ The Board acknowledges differences between section 404 and QC 1000, but section 404 is similar to QC 1000 in that section 404 was a policy shock that led large public companies to improve their internal control practices. In addition, while QC 1000 is not an internal control framework *per se*, it does reflect similar principles as COSO, the industry standard control framework that was widely relied upon to implement section 404. One commenter observed that the requirements under QC 1000 are similar in certain ways to the requirements related to ICFR under Sarbanes-Oxley for companies and suggested that the impacts of QC 1000 on auditors will be similar to the impact Sarbanes-Oxley had on companies notwithstanding key differences between a company's ICFR and an audit firm's QC system.

⁴⁹³ Based on a sample of companies that voluntarily disclosed Section 404 cost information in their SEC filings during the period Jan. 2003 to Sept. 2005, one study found that the mean total compliance costs for Section 404 was \$2.2 million (\$3.7 million adjusted for inflation), and the median was \$1.2 million (\$2.0 million adjusted for inflation). See Jagan Krishnan, Dasaratha Rama, and Yinghong Zhang, *Costs to Comply with SOX Section 404*, 27 *Auditing: A Journal of Practice & Theory* 169 (2008). Using a sample of Fortune 1000 companies, another study estimated the companies spent an average of \$5.9 million (\$9.6 million adjusted for inflation) to comply with Section 404 in the first year of implementation. See Charles River Associates, *Sarbanes-Oxley 404 Costs and Remediation of Deficiencies: Estimates from a Sample of Fortune 1000 Companies* (2005). Another study found that direct costs of Section 404 fell by as much as 40% by the second year after implementation and varied significantly by company size. See John C. Coates IV, *The Goals and Promise of the Sarbanes-Oxley Act*, 21 *Journal of Economic Perspectives* 91 (2007). Another study reported an SEC survey sample that showed an overall average Section 404 compliance expense of \$1.2 million (\$1.7 million adjusted for inflation) in the latest fiscal year before the survey (Dec. 2008 to Jan. 2009) and respondents reported a decline over time in such costs. See Cindy R. Alexander, Scott W. Bauguess, Gennaro Bernile, Yoon-Ho Alex Lee, and Jennifer Marietta-Westberg, *Economic Effects of SOX Section 404 Compliance: A Corporate Insider Perspective*, 56 *Journal of Accounting and Economics* 273 (2013). To adjust results from the studies for inflation, PCAOB staff used an inflationary factor as of the third quarter 2023 from the current dollar index number of the Employment Cost Index for private workers employed in the professional, scientific, and technical services industry published by the U.S. Bureau of Labor Statistics (available at <https://www.bls.gov/eci/data.htm>). This inflationary adjustment does not account for any potential differences between QC 1000 costs and Section 404 costs or any potential structural changes over time.

a. Direct and Indirect Costs of the Proposed Requirements

The Board expects the requirements will lead to several direct and indirect costs. There will be a direct cost to audit firms to design a QC system that complies with QC 1000. For example, firms will likely spend time reviewing QC 1000; assigning roles and responsibilities; identifying staffing and training needs; and developing a set of quality objectives, quality risks, and quality responses. Once a QC system is designed, firms will incur costs to monitor, identify, and assess changes to conditions, events, and activities that indicate modifications to the firm's quality objectives, quality risks, or quality responses may be needed. Some firms may outsource certain aspects of QC system design. The Board also expects that customization will be necessary to ensure that each QC system design appropriately addresses each firm's circumstances. The extent of the design costs will likely depend on facts and circumstances unique to each firm. Among firms that will be subject to other QC standards, which the Board believes represents most firms, the design costs will likely be reduced and limited to incremental requirements around ethics, independence, monitoring, and remediation.

For full applicability firms—those that will be required to implement and operate an effective QC system—there will likely be additional costs. Firms may need to implement fixed resources (e.g., people, financial, technological, or intellectual) prior to operating their QC system. For example, a firm may need to invest in an IT system or train individuals having QC roles or responsibilities. Several commenters identified significant implementation costs and called for an extended implementation period due to these costs. Describing the results of its recent survey of assurance service QC leaders, one commenter reported that obtaining “buy in” and acceptance from organizational members is the most common challenge firms face when implementing changes to their QC systems.⁴⁹⁴ As discussed, the Board agrees there will be implementation costs; however, these implementation costs will be reduced to the extent that firms already implement the requirements to comply with the actions of other standard setters or due to other developments. Furthermore, the Board expects the design and implementation

costs will be largely fixed in nature and will decline over time.

Firms may also incur new operating costs, at the firm level and the engagement level. At the firm level, firms may require additional resources to administer new or revised quality responses after they are implemented, execute the annual risk assessment, perform the annual evaluation of the QC system, report the results of the evaluation to the PCAOB using the same PCAOB platform as the other reporting forms, and prepare and retain the required documentation. Several commenters identified significant operating costs. For example, one commenter argued that the proposed independent oversight function could entail insurance costs. At the engagement level, engagement team time may be required to execute new or revised quality responses. For example, an engagement team may carry out procedures regarding continuance of the firm's relationship with the client served by that engagement team. These operating costs will be reduced for firms that would be subject to other standard setters or other developments.

Several commenters asserted that the documentation costs, as originally proposed, could be particularly onerous. For example, several commenters asserted that firms would be required to retain large volumes of documentation to support the operation of the firm's quality responses for each instance related to all years for which firms are required to maintain such documentation. One commenter noted that information evidencing the operation of a firm's QC system can vary in size, type, and storage requirements and that the costs of modifying the firm's existing IT systems to comply with the documentation requirement could be significant. Some commenters noted that the amount of documentation to be retained is expected to require considerably more storage space for each evaluation period, which the commenters suggested translates to a need for new servers and extended licensing agreements. One commenter said that firms that change their systems will have to maintain licenses for old systems for up to seven years. The same commenter said the seven-year retention period goes well beyond the retention requirements of ISQM 1 and SQMS 1 and asserted that firms with a significant private company client base would be challenged to have different documentation retention policies since many aspects of quality control relate to the firm as a whole. Some commenters suggested that retaining sensitive information introduces heightened

⁴⁹⁴ See Hayne, et al., *Managing Quality Control Systems*.

cybersecurity risks for firms, firm personnel, clients, and other stakeholders. The Board acknowledges that the documentation requirement could create costs for firms, including costs related to retention and cybersecurity infrastructure. To clarify the expected cost burden, the discussion above notes that documentation of every aspect of the operation of the firm's QC system may not be required to evidence that each quality response operated effectively.

Several commenters asserted that smaller firms may be especially affected by the new QC requirements, including requirements incremental or alternative to ISQM 1 and SQMS 1. One commenter said that smaller firms will need to hire consultants or additional staff for the monitoring, remediation, and evaluation functions, notwithstanding the scalability of QC 1000. Another commenter asserted that QC 1000 will impose disproportionate costs on smaller firms but noted that the commenter did not analyze in detail the cost of each incremental requirement and therefore did not have an estimate of the disproportionate costs. Relatedly, research finds that implementation and operating costs of internal control frameworks precipitated by Sarbanes-Oxley are proportionally greater for smaller companies.⁴⁹⁵

The Board acknowledges that the direct costs will likely vary depending on the size of the firm and the nature of its audit practice. Larger PCAOB audit practices that already have extensive QC systems in place may benefit from economies of scale or scope when incorporating the new requirements into their existing systems, which would decrease the cost of QC 1000 per engagement. Larger PCAOB audit practices will be able to distribute fixed implementation costs over a larger number of engagements, while smaller practices will distribute fixed implementation costs over a smaller number of engagements. On the other hand, it may also be difficult for firms with more complex clients and diverse client portfolios—characteristics of larger PCAOB audit practices—to implement effective QC systems. To the extent that smaller firms may be disproportionately impacted as commenters have suggested, the Board continues to believe that the principles-based features and scalable nature of QC 1000, described in greater detail above, as well as the 100-issuer threshold for some provisions, help to mitigate their

costs because smaller firms will rely on proportionally fewer resources for design, implementation, and operation of their QC systems.

In addition to the direct costs to auditors to comply with the requirements, indirect costs may arise. To the extent that compliance with the requirements will improve compliance with applicable professional and legal requirements at the engagement level, costs may increase for the affected engagements. For example, in bringing their work into compliance with PCAOB auditing standards, some engagement teams may gather additional or more persuasive audit evidence and prepare more documentation than they previously did. However, firms should be incurring these costs already.

Audited companies may also incur indirect costs related to the requirements. For example, some commenters asserted that the 100-issuer threshold could deter triennially inspected firms from accepting new public company audit engagements or encourage firms to resign from existing audit engagements to avoid crossing the 100-issuer threshold. Although the Board recognizes this possibility, for context regarding the number of firms currently around the 100-issuer threshold, PCAOB staff analysis of audit reports included in SEC filings indicates that, during the 2022 calendar year, two NAFs audited between 80 and 100 issuers and two NAFs audited between 100 and 120 issuers. Firms may pass on part of any increased costs they incur at the firm or engagement level by raising the fees they charge their clients. In addition, to the extent that the requirements improve compliance with applicable professional and legal requirements, some audited companies could face additional costs to respond to their auditors' requests for additional or more extensive audit evidence. Audited companies may incur other costs due to changes in audit firm QC policies and procedures. For example, if QC 1000 results in changes to firms' client acceptance and continuance practices, firms may require greater fees or refuse to accept or retain high-risk clients. While this outcome would represent a cost to audited companies, the result could be a more efficient audit market if riskier companies pay more. These indirect costs will be reduced to the extent that firms will have already implemented the requirements in response to similar actions of other standard setters or due to other developments.

b. Costs of Key Provisions

i. Scaled Applicability

Scaled-applicability firms will incur the design costs discussed above. Should a scaled-applicability firm ever become subject to the implementation and operation requirements, the firm will then incur the implementation and operation costs discussed above. As with other registered firms, the costs to scaled-applicability firms will be less to the extent they will already be complying with ISQM 1 or SQMS 1. Firms and a related group suggested allowing firms that do not perform engagements the flexibility to design their QC system in accordance with another QC standard, such as ISQM 1 or SQMS 1, to help manage costs. However, the Board expects the design costs for those firms to be limited to incremental requirements around ethics, independence, monitoring, and remediation. Furthermore, scaled-applicability firms may choose to avoid the design costs by withdrawing from PCAOB registration given that they are not required to be registered.

ii. In-Process Monitoring Activities

The Board believes the in-process monitoring requirement may contribute to the direct and indirect costs discussed above such as: (1) developing documentation, (2) providing training, (3) gathering additional audit evidence, and (4) other potential indirect costs such as the time required of issuers to provide their auditor with additional or more extensive audit evidence. The costs will depend on the extent to which firms already have in-process monitoring activities in place. In addition, in-process monitoring may result in increased audit fees. Information gathered through PCAOB inspection activities indicates that 11 out of 14 annually inspected firms perform some in-process engagement monitoring activities.

iii. Firm Governance Structure

The Board believes there could be costs to design, implement, and operate the oversight function (*i.e.*, EQCF). For example, firms that are required to incorporate the oversight function into their governance structure for the first time may incur costs when retaining appropriate individuals from outside of the firm.⁴⁹⁶ Firms with an existing

⁴⁹⁵ See, e.g., John C. Coates and Suraj Srinivasan, *SOX after Ten Years: A Multidisciplinary Review*, 28 Accounting Horizons 627 (2014).

⁴⁹⁶ According to Spencer Stuart, the average compensation per non-employee director was \$327,764 in 2023. See 2023 U.S. Spencer Stuart Board Index (2023), available at <https://www.spencerstuart.com/-/media/2021/october/ssbi2021/us-spencer-stuart-board-index-2021.pdf> (analyzing 489 DEF-14A proxy statements filed by

oversight function may incur costs to find different individuals to fill the role. In addition, firms with an existing oversight function may incur incremental costs to incorporate the baseline requirement to evaluate, at a minimum, significant judgments made and the related conclusions reached by the firm when evaluating and reporting on the effectiveness of its QC system.

Several commenters expressed concern that the oversight function would be costly or difficult to fulfill, especially for firms that audit between 100 and 500 issuers. One commenter suggested the oversight function could add costs that ultimately have to be passed on through higher audit fees, which investors in smaller issuers are unlikely to support, particularly when the costs are spread over a small amount of invested public capital in a firm's issuer audits clients. Conversely, one commenter said that the costs of the oversight function could be reduced by engaging an independent accounting firm to provide weekly advisory services.

To help address these cost concerns, the requirement will allow firms to implement an oversight function into their QC system suitable for their circumstances. Costs, as well as the associated benefits, could be attenuated for U.S. GNFs by the fact that all of the U.S. GNFs indicate, as of the 2020 inspection cycle, that they already have a governance structure that includes a non-employee.

iv. The Automated Independence Process

The Board believes there could be costs to design, implement, and operate the required automated process to identify investments in securities that might impair independence. The costs will depend on the extent to which firms already have such an automated process in place. Information gathered through PCAOB inspection activities indicates that nine out of 14 annually inspected firms already have one in place. The remaining five have processes in place that are not fully automated. Firms will be able to automate the process in a way that is suitable to their unique facts and circumstances. Most firms will likely need to: (1) convert their restricted entity list into a searchable electronic form; (2) maintain the electronic restricted entity list; and (3) develop

queries that can compare a manager's or partner's relevant investments in securities to the electronic restricted entity list. Some firms may choose to integrate the automated process with existing systems related to client acceptance or time and expense. Firms with simple restricted entity lists (*e.g.*, fewer clients, fewer subsidiaries) or simpler QC policies and procedures for restricted entities (*e.g.*, any investment in any security of a restricted entity is restricted) may require less investment in software and expertise than other firms.

Several commenters said that the proposed automated process will entail significant costs. One commenter emphasized that there will be upfront and ongoing investments in technology and other overhead to operate such a process. Another commenter noted that implementing and maintaining an automated independence monitoring system is costly for smaller firms, which audit predominantly privately held companies and have not previously been subject to the automated independence system requirement under SEC rules. One commenter said it was unaware of any truly off-the-shelf system responsive to the proposed requirement. One commenter emphasized that for firms that audit between 100 and 500 issuers, the main potential downside of an automated process is the associated time and incremental cost to develop an efficient and effective system. The commenter noted that, in addition to software costs, there will be costs to oversee the system to ensure the data entered are correct and firm personnel are trained to use the system. Another commenter noted that the six largest firms represent 60% of issuers and approximately 98.7% of the capital markets and asserted that the automated independence process will nearly triple the number of firms required to implement automated investment tracking systems but pick up less than 15% of issuers, which represent less than 1% of the capital markets. The same commenter also asserted that the differences in size, scope, nature, and complexity between the six largest annually inspected firms and other annually inspected firms can be immense and that more than 80% of the commenter's issuer client count consists of either Form 11-K audits or audits of smaller companies, which have less impact on capital markets. While the commenter provided these figures in response to costs of the automated independence process, the same figures could apply to the costs and benefits of each of the key policy

provisions that invoke the 100-issuer threshold.

To help address these views, the final standard clarifies that the required automated process: (1) will apply only to the identification of relevant investments in securities and (2) will permit firms to rely on firm professionals accurately self-reporting and entering their investments into the system (*e.g.*, direct brokerage feeds will not be expressly mandated). In addition, the Board believes that existing software products likely could be adapted to respond to the requirements.

Furthermore, off-the-shelf systems more tailored to the requirements may enter the market in the future.

Notwithstanding the commenters' views, the Board retained the automated independence process requirement, and acknowledges there will be costs to design, implement, and operate it.

v. Complaints and Allegations Policies and Procedures

The Board expects the policies and procedures regarding complaints and allegations will entail direct costs to firms to design, implement, and maintain. Most notably, firms will incur additional variable costs to receive, investigate, and address complaints and allegations. Firms that issued audit reports with respect to more than 100 issuers during the prior calendar year will incur costs to implement confidentiality protections. The costs will depend on the extent to which firms already have policies and procedures regarding complaints and allegations in place. Information gathered through PCAOB inspection activities indicates that 10 out of 14 annually inspected firms already have hotlines in place that may satisfy certain of the complaints and allegations requirements.⁴⁹⁷

vi. Reporting the Annual QC System Evaluation

The Board expects the requirement to report the annual QC system evaluation to the PCAOB will entail an additional annual cost to firms to prepare Form QC. However, since firms will already be required to perform and document the evaluation, any additional costs associated with preparing Form QC should be minimal. The requirement may also result in some increased

S&P 500 companies with the SEC between May 1, 2022, and Apr. 30, 2023). PCAOB staff notes that variation between the responsibilities of an oversight function and a non-employee director function may limit the relevance of this cost reference to some extent.

⁴⁹⁷ According to one hotline vendor that posted their service prices online, the annual fee for a hotline that covers up to 75 employees starts at \$1,200 and the annual fee for a hotline that covers more than 5,000 employees starts at \$7,000 (*see* <https://www.allvoices.co/basic-purchase>). The Board notes that the complaints and allegations provisions include more than having a hotline.

litigation risk to the extent that information reported to the PCAOB is not subject to privilege under section 105(b)(5) of Sarbanes-Oxley, and to the extent that reporting of this information to a third party may vitiate other privileges that otherwise could have been used to protect the information from compelled disclosure in third-party actions. Non-protected material may become subject to compulsory production, which could impose indirect costs on firms to the extent that legal or other consequences may flow from that production.

vii. Certification of the Annual QC System Evaluation

The certification requirement itself may not impose much direct cost on firms because the evaluation activities precede certification. However, to the extent that firms choose to implement a more robust internal compliance infrastructure (e.g., by requiring sub-certifications from personnel with direct responsibility for certain functions), those costs could also be attributable to the certification requirement. Moreover, firms may be exposed to litigation costs because the certifications in Form QC are not subject to privilege under section 105(b)(5) of Sarbanes-Oxley, meaning that third parties may be able to compel production of the certifications, and the certifications may have an impact in third-party litigation. For example, the threat of liability for negligent conduct could lead to costs if individuals demand additional remuneration or take additional steps to act reasonably and demonstrate that they have acted reasonably (e.g., assuring themselves that the QC system is appropriately designed) or to defend against enforcement allegations. The Board believes, however, that the internal compliance exercise, and even potentially the threat of third-party litigation, can reinforce the importance of the firm's QC system within the firm, which in turn can help produce the benefits the Board expects this provision will generate.

viii. Responding to Engagement Deficiencies Identified After Issuance of the Audit Report

The amendments to AS 2901, *Consideration of Omitted Procedures After the Report Date*, and related amendments to AT No. 1 and AT No. 2 will contribute to the engagement-level costs discussed above to the extent auditors will perform additional procedures to obtain sufficient appropriate evidence or take additional action to prevent future reliance on insufficiently supported audit opinions

(or review reports in the case of review engagements) that are being relied on. The Board expects the requirement to extend the scope of AS 2901 to include the ICFR audit within its scope will be particularly impactful because the audit of internal control over financial reporting is both resource-intensive⁴⁹⁸ and a common and recurring area of deficiency.⁴⁹⁹

vii. SECPS Requirements

The requirements will refine, integrate into QC 1000, and extend to all firms the SECPS member requirements currently required under PCAOB Rule 3400T. The Board expects this will increase development, implementation, and operating costs for firms not already subject to these requirements. However, the Board believes the costs should be minimal because, based on its oversight activities, the Board believes these firms already have in place policies and procedures related to compliance with SEC and PCAOB independence rules.

3. Unintended Consequences

The requirements could give rise to unintended consequences. Overall, however, the Board expects any potential unintended consequences will be mitigated by other factors.

a. Human Capital

Some firms may require additional staff resources to implement the requirements. To meet this demand, firms may transfer personnel from engagement-level roles to QC roles. This could create a risk that engagements are insufficiently staffed. Alternatively, some firms may assign more junior staff to QC roles or to new openings on engagements. This could create a risk that QC system or engagement personnel lack sufficient training or experience. One commenter reported the commenter's own analysis to demonstrate that audits are largely conducted by non-CPAs with limited experience in the field of auditing. QC 1000 includes quality objectives that mitigate these risks. For example, firms will be required to establish quality objectives that individuals who are assigned to engagements or perform QC system activities have the competence, objectivity, authority (in the case of activities within the QC system), and time to perform their responsibilities in

accordance with applicable professional and legal requirements and the firm's policies and procedures.⁵⁰⁰

Some commenters argued that the costs of QC 1000 would be especially significant due to labor shortages. One commenter asserted that an aggressive enforcement atmosphere may create disincentives for individuals to join the profession, harming the talent pipeline that is necessary for the production of high-quality audits. Another commenter raised concerns that recruiting and retaining partners and employees for a firm's QC system will be a tremendous challenge for firms willing and able to absorb additional costs to properly implement the requirements of QC 1000 given the tight labor market. One commenter reported that some market research indicates significant declines in the number of new CPA candidates and annual accounting degree completions.⁵⁰¹ The commenter also reported commentary from a survey that reveals the largest accounting firms regularly score low along dimensions that are most indicative of their desirability as places to work.⁵⁰² Another commenter cited news articles⁵⁰³ and academic research⁵⁰⁴ that suggest attracting and retaining talent is a serious concern for accounting firms and university accounting programs. However, based on its preliminary survey research, another commenter reported that some QC leaders do not feel resource constrained.⁵⁰⁵

The Board acknowledges the commenters' concerns about the potential impact on staff resources. However, the potential impact on staff resources is likely the result of the interplay among numerous factors in the labor market, such as the rigor of qualifying for and completing the requirements for CPA licensure and the relatively low starting salaries being cited by college students as one of the main hurdles to choosing accounting as a major. To meet increased demand for staff resources, some firms may choose to hire additional experienced staff. It is

⁵⁰⁰ See QC 1000.44c. and e.

⁵⁰¹ See AICPA Trends Report.

⁵⁰² See Mark Kolakowski, *Best Accounting Firms (Vault Top 50 Accounting Firms)* (Jan. 14, 2020).

⁵⁰³ See, e.g., Lindsay Ellis, *Why so Many Accountants are Quitting*, Wall St. J. (Dec. 28, 2022); Stephen Foley, *Accountants Work to Shed "Boring" Tag Amid Hiring Crisis*, Financial Times (Oct. 3, 2022).

⁵⁰⁴ See, e.g., Hermanson, et al., *The Work Environment in Large Audit Firms* A38; Dana R. Hermanson, Heather M. Hermanson, Susan D. Hermanson, *Where is Public Company Auditing Headed?*, 90 CPA Journal 54 (2020); Westermann, et al., *PCAOB Inspections* 694.

⁵⁰⁵ See Hayne, et al., *Managing Quality Control*.

⁴⁹⁸ See, e.g., U.S. Securities and Exchange Commission Office of Economic Analysis, *Study of the Sarbanes-Oxley Act of 2002 Section 404 Internal Control over Financial Reporting Requirements* (Sept. 2009), at Table 8 (reporting that roughly one-third of total audit fees may be attributable to the ICFR audit).

⁴⁹⁹ See, e.g., 2020 Inspection Observations Preview.

possible that the labor demand shock could result in increased wages and potentially higher audit fees, which could be exacerbated by the concentration of large firms in the audit market. Higher wages could in turn help firms attract and retain a skilled workforce or encourage qualified individuals to take essential roles at firms.⁵⁰⁶ The principles-based features and scalable nature of QC 1000 described above, as well as the 100-issuer threshold for some provisions, help mitigate this risk because fewer resources will be required for firms based on those features.

b. Competition

The requirements could also cause firms to exit the public company audit market or deter other firms from future entry. Entry deterrence could be exacerbated by the fact that being registered with the PCAOB will subject firms to certain QC requirements even if they do not perform engagements. Several commenters agreed that the proposed requirements, if adopted, could impact competition. One commenter expressed concern that the incremental requirements of QC 1000 relative to other QC standards could lead smaller high-quality firms to exit the market. One commenter asserted that the certification requirement would be an especially significant driver of exit, particularly for smaller firms. Some commenters suggested that the design requirement for scaled-applicability firms could lead some scaled-applicability firms to deregister with the PCAOB or create a barrier to entry. One commenter added that the design requirement for scaled-applicability firms could impact audit markets beyond the U.S. by creating a disincentive for foreign firms to serve specific audit markets. Another commenter suggested that further enhancing the scalability of QC 1000 may be helpful for smaller firms to stay competitive. One commenter noted that QC 1000 requirements may serve as an impediment to audit firm mergers and acquisitions and otherwise perturb market activity. Correspondingly, less consolidation could mitigate concentration or help preserve a competitive dynamic amongst firms. Nevertheless, the presence of fewer

firms could reduce competition in the public company audit market even in light of additional scalability or fewer mergers and acquisitions. Some commenters said that some firms may resign existing issuer clients or decline new ones to avoid incremental QC 1000 requirements for firms that issue more than 100 audit reports. This could lead to a further reduction in competition for engagements that these firms would otherwise compete. This reduction in competition would likely only apply to actual or potential issuer clients of firms that are close to the 100-issuer threshold. As noted above, PCAOB staff analysis of audit reports included in SEC filings indicates that, during the 2022 calendar year, the number of firms currently around the 100-issuer threshold includes two NAFs that audited between 80 and 100 issuers and two NAFs that audited between 100 and 120 issuers.

Confirming the widely held view that audit firms compete on price, some research suggests that reduced competition is indeed associated with higher audit fees.⁵⁰⁷ However, any exit would likely be limited primarily to firms with small market shares and to the smaller issuer or broker-dealer audit markets, which research suggests tend to be competitive.⁵⁰⁸ For example, firms

⁵⁰⁷ See, e.g., Joshua L. Gunn, Brett S. Kawada, and Paul N. Michas, *Audit Market Concentration, Audit Fees, and Audit Quality: A Cross-Country Analysis of Complex Audit Clients*, 38 *Journal of Accounting and Public Policy* 1 (2019).

⁵⁰⁸ While research generally has focused on competition for the largest public company audits and the corresponding concentration amongst the largest audit firms, less is known about market forces within the smaller audit firm market. However, some research has studied competitive aspects of the smaller firm market. See, e.g., Tracy Ti Gu, Dan A. Simunic, Michael T. Stein, Minlei Ye, and Ping Zhang, *The Market for Audit Services: The Role of Market Power*, 19 *Journal of International Accounting Research* 3 (2020) (concluding that small public companies can potentially purchase audit services from any audit firm and that the number of suppliers to small public companies is relatively higher than the number of suppliers to large public companies); Kenneth L. Bills and Nathaniel M. Stephens, *Spatial Competition at the Intersection of the Large and Small Audit Firm Markets*, 35 *Auditing: A Journal of Practice and Theory* 23 (2016) (concluding that smaller and larger firms compete locally in some cases); Andrew Kitto, Phillip T. Lamoreaux, and Devin Williams, *Do Entry Barriers Allow Low Quality Audit Firms to Enter the Public Company Audit Market?*, available on SSRN: [https://ssrn.com/abstract=3572688\(2023\)](https://ssrn.com/abstract=3572688(2023)) (concluding that current barriers to entry likely deter some audit firms from entering the audit market but that current barriers fail to prevent entry by firms that are significantly lower quality compared to incumbent firms); Brant Christensen, Kecia Williams Smith, Dechun Wang, and Devin Williams, *The Audit Quality Effects of Small Audit Firm Mergers in the United States*, 42 *Auditing: A Journal of Practice & Theory* 75 (2023) (concluding that audit quality decreases post-merger based on data regarding mergers of very small audit firms).

that would manage their client portfolio to avoid incremental QC 1000 requirements would likely prefer to resign (or decline to accept) smaller issuer clients than larger issuer clients. Moreover, some research suggests that reduced competition may have a positive impact on audit quality because it curtails issuers' opportunity to opinion shop.⁵⁰⁹ Compounding this effect, the requirements may further deter opinion shopping as a basis for competition to the extent they would improve auditors' compliance with professional standards. One commenter argued that opinion shopping is not prevalent and any reduction in opinion shopping would be minimal.

c. Network Resources

Some commenters expressed concern that the requirements could diminish the availability of global network resources and that smaller firms around the world could decline to assist U.S. firms in their global audits. One commenter added that this could be detrimental to overall engagement quality. Several factors could mitigate this potential unintended consequence. First, staff analysis of 2021 Form AP filings finds that 74% of all audits (32% of Fortune 500 audits) do not use other auditors.⁵¹⁰ Second, this potential unintended consequence would likely be limited primarily to firms that lack the network resources to implement QC 1000. One academic study finds that 94% of component auditors identified on Form AP are affiliated with the principal auditor (99% when the principal auditor is a GNF).⁵¹¹ Third, other auditors that do not play a substantial role on any PCAOB engagement would be able to deregister with the PCAOB and continue to perform their existing roles on the engagements. Fourth, the competitiveness of the smaller issuer audit market suggests that principal auditors would be able to retain a different component auditor of comparable quality. Finally, to the extent the requirements would lead a firm to retain a lower-quality

⁵⁰⁹ See, e.g., Nathan J. Newton, Julie S. Persellin, Dechun Wang, and Michael S. Wilkins, *Internal Control Opinion Shopping and Audit Market Competition*, 91 *The Accounting Review* 603 (2016); Nathan J. Newton, Dechun Wang, and Michael S. Wilkins, *Does a Lack of Choice Lead to Lower Quality? Evidence From Auditor Competition and Client Restatements*, 32 *Auditing: A Journal of Practice & Theory* 31 (2013).

⁵¹⁰ See PCAOB Rel. No. 2022-002, at Figure 2.

⁵¹¹ See William M. Docimo, Joshua L. Gunn, Chan Li, and Paul N. Nicholas, *Do Foreign Component Auditors Harm Financial Reporting Quality? A Subsidiary-Level Analysis of Foreign Component Auditor Use*, 38 *Contemporary Accounting Research* 3113 (2021).

⁵⁰⁶ There are some indications that retention and recruitment of staff is currently a challenge for audit firms. See, e.g., Persellin, et al., *Auditor Perceptions* 95; AICPA Private Companies Practice Section, *2021 PCPS CPA Top Issues Survey*; AICPA, *2021 Trends: A Report on Accounting Education, the CPA Exam and Public Accounting Firms' Hiring of Recent Graduates* ("AICPA Trends Report") (Apr. 2022).

component auditor, existing PCAOB standards related to audits involving other auditors could help mitigate the risk that the new component auditor performs a low-quality component audit.⁵¹² It is possible that, despite the requirements, firms may not improve compliance with applicable professional and legal requirements when performing their engagements. For example, personnel assigned to QC roles may adopt a perfunctory, “check the box” attitude toward compliance. The firm’s risk assessment process and monitoring and remediation process requirements, which require personnel assigned to QC roles to think proactively about the reasonable assurance objective, could help to mitigate this risk. As another example, engagement partners may overestimate the ability of their firm’s QC system to support achievement of the reasonable assurance objective and relax their efforts to self-monitor or monitor others. While QC 1000 centralizes responsibility for QC to a degree, other requirements could mitigate this risk. For example, individual responsibility features prominently in QC 1000 and PCAOB auditing standards emphasize the responsibility of the engagement partner for the engagement and its performance.⁵¹³

d. Accountability

Some commenters expressed concern that the accountability provisions of QC 1000 could have potentially harmful unintended consequences. For example, one commenter asserted that good faith actions with regard to supervisory responsibilities could become subject to PCAOB enforcement. Some commenters suggested that the roles and responsibilities requirements could reduce audit quality or increase costs by creating a disincentive for the most qualified individuals to take on the specified roles. One commenter noted that individual certification poses a potential threat of additional liability and could affect the recruitment of talented individuals needed to fill critical roles within firms. Another commenter noted that for firms with an issuer practice that makes up a small portion of the overall practice, it can be difficult to find partners to fill lead and

engagement quality reviewer roles on engagements when those roles are subject to a higher risk of individual enforcement actions.

The Board acknowledges that, in addition to positive consequences, accountability can have negative consequences, such as disincentives from taking on QC roles with greater accountability. One commenter suggested that the incorporation of rewards into the firms’ accountability model could mitigate this potential unintended consequence. QC 1000 contemplates that the firm’s compensation plans and performance evaluations will appropriately incentivize firm personnel to fulfill their assigned responsibilities⁵¹⁴ and that firm leadership will be held accountable for quality, including through their performance evaluations and compensation.⁵¹⁵ Depending on the firm’s specific quality risks, including the risk that qualified individuals may be unwilling to take on QC roles, firms can incorporate both positive incentives (“carrots”) and negative incentives (“sticks”) in the design of their incentive plans.

e. Scalability

One commenter expressed concern based on academic research that limiting the applicability of certain requirements to firms of a certain size could give rise to audit quality differences between larger and smaller firms. In general, the incremental requirements for larger PCAOB audit practices are less suitable to smaller PCAOB audit practices’ QC systems. For example, a smaller firm may not need an automated system to track investments if it has a stable number of issuer clients and a small group of persons subject to independence requirements. But if a smaller firm does not achieve its quality objectives or the reasonable assurance objective, it will have to take remedial action, which could include implementing some or all of the incremental QC system features that are expressly required for larger PCAOB audit practices.

f. Design Requirements Under Scaled Applicability

Some commenters expressed concern that scaled-applicability firms could design QC systems inappropriate for the future circumstances that would arise should the firm eventually become a full-applicability firm. One commenter cited research that suggests audit firm personnel designing a QC system to

address hypothetical future circumstances will need to overcome numerous cognitive biases.⁵¹⁶ The Board believes this potential unintended consequence is mitigated by QC 1000’s proactive approach. For example, the firm will be required to establish policies and procedures to monitor, identify, and assess changes to conditions, events, and activities that indicate modifications to the firm’s quality objectives, quality risks, or quality responses may be needed. When such changes are identified, the firm will be required to determine what, if any, modifications are needed to make them on a timely basis. In effect, a scaled-applicability firm’s QC system design should be appropriate for its circumstances in the event it becomes a full-applicability firm.

g. Other Potential Unintended Consequences

Because firms’ QC systems will likely operate over all of their engagements, including those that are not subject to PCAOB standards, the engagement-level costs discussed above could apply to those engagements as well. Moreover, one commenter asserted that firms with a significant private company client base will be challenged by different documentation retention policies based on client base since many aspects of QC relate to the firm as a whole. Correspondingly, the requirements could improve compliance on those engagements because they would be governed by more effective QC policies and procedures. Indeed, one commenter said that requiring all firms to design a QC system that complies with QC 1000

⁵¹⁶ See, e.g., Paul J.H. Schoemaker, *Forecasting and Scenario Planning: The Challenges of Uncertainty and Complexity*, in Blackwell Handbook of Judgment & Decision Making, eds. D.J. Koehler and N. Harvey, 274 (2004); Edward J. Joyce and Gary C. Biddle, *Anchoring and Adjustment in Probabilistic Inference in Auditing*, 19 Journal of Accounting Research 120 (1981); Noel Harding and Ken T. Trotman, *Improving Assessments of Another Auditor’s Competence*, 28 Auditing: A Journal of Practice & Theory 53 (2009); Byron J. Pike, Mary B. Curtis, and Lawrence Chui, *How Does an Initial Expectation Bias Influence Auditors’ Application and Performance of Analytical Procedures?*, 88 The Accounting Review 1413 (2013); Amos Tversky and Daniel Kahneman, *Judgment under Uncertainty: Heuristics and Biases*, 185 Science 1124 (1974); Steven M. Glover, James Jiambalvo, and Jane Kennedy, *Analytical Procedures and Audit-Planning Decisions*, 19 Auditing: A Journal of Practice & Theory 27 (2000); Vicky B. Hoffman and Mark F. Zimbelman, *Do Strategic Reasoning and Brainstorming Help Auditors Change their Standard Audit Procedures in Response to Fraud Risk?*, 84 The Accounting Review 811 (2009); Tim D. Bauer, Sean M. Hillison, Mark E. Peecher, and Bradley Pomeroy, *Revising Audit Plans to Address Fraud Risk: A Case of “Do as I Advise, Not as I Do”?*, 37 Contemporary Accounting Research 2558 (2020).

⁵¹² See, e.g., PCAOB Rel. No. 2022–002.

⁵¹³ See, e.g., QC 1000.42a.(1); AS 1201.03. The Board has also proposed to clarify the engagement partner’s existing responsibilities for supervision and review in AS 1201, AS 1215, and AS 2101 to provide more specificity about the engagement partner’s responsibility to exercise due professional care related to supervisory and review activities required to be performed under existing auditor requirements. See PCAOB Rel. No. 2023–001 at 15.

⁵¹⁴ See QC 1000.44g.

⁵¹⁵ See QC 1000.25b.

could have a beneficial impact on private company audits.

Research on other quality management and enterprise risk management systems suggests other potential unintended consequences. For example, research on ISO 9000 adoption indicates that it may reduce staff morale, stifle innovation, and require excessive levels of documentation.⁵¹⁷ The principles-based features and scalable nature of QC 1000 described above, as well as the 100-issuer threshold for some provisions, help mitigate these concerns by providing firms the ability to design, implement, and operate policies and procedures to support achievement of the reasonable assurance objective based on their facts and circumstances.

Alternatives Considered

During the development of the requirements, the Board considered a number of alternative approaches to address the need described above. This section explains: (1) why standard setting is preferable to other policy-making approaches, such as providing interpretive guidance or enhancing inspection or enforcement efforts; (2) why the chosen standard-setting approach is preferable to other standard-setting approaches; and (3) key policy choices made in determining the details of the standard-setting approach.

1. Why Standard Setting Is Preferable to Another Approach

As potential alternatives to standard setting, the Board considered whether interpretive guidance or greater focus on inspections or enforcement could better address the need described above.

Interpretive guidance assists firms in the implementation of existing PCAOB standards and rules and can advance audit quality by establishing a common understanding of a firm's obligations under PCAOB standards and rules. For example, interpretive guidance may address, among other things, specific, common audit deficiencies identified during PCAOB inspections and the applicable requirements under PCAOB standards and rules. By contrast, as discussed above, some firms' QC systems appear to not be providing reasonable assurance of compliance generally. Moreover, current PCAOB QC standards were developed decades ago

in a very different audit environment and have not been updated to reflect the risk-based, proactive approach to QC that the Board believes would be most effective. Therefore, the Board believes revisions to the current PCAOB QC standards are needed to require firms to make the necessary enhancements to their QC systems to help drive compliance with professional standards.

While the PCAOB will continue to address firms' compliance with PCAOB standards and rules through inspection and enforcement activities, QC standard setting provides certain unique benefits. Firms' QC systems operate over all aspects of all issuer audits and broker-dealer engagements, whereas PCAOB inspections assess compliance with only certain aspects of the issuer audits and broker-dealer engagements selected for review. In addition, inspection and enforcement efforts take place after the engagement has occurred and after investors and other financial statement users have potentially suffered harm. Therefore, greater focus on inspecting and enforcing compliance with PCAOB standards and rules may not be as effective as updating the QC standards and amending other related standards.

2. Why the Chosen Standard-Setting Approach Is Preferable to Other Standard-Setting Approaches

QC 1000 shares the same basic structure as ISQM 1 and SQMS 1. The Board also considered basing QC 1000 on a different quality management framework, such as COSO or ISO 9001, or developing its own risk-based approach. The essential features of these other quality management frameworks are broadly similar to ISQM 1 and SQMS 1. For example, they typically are risk-based and focus on monitoring and remediating deficiencies. However, ISQM 1 and SQMS 1 have the further advantage of being specifically tailored to audit firms. Furthermore, an original risk-based approach would likely include the same essential features as ISQM 1 and SQMS 1. Overall, the Board believes that the benefits of basing QC 1000 on a different quality management framework or an original PCAOB risk-based approach (e.g., improved compliance with applicable professional and legal requirements) would be similar to the benefits of using a structure similar to ISQM 1 and SQMS 1.

Basing QC 1000 on a different quality management framework or an original PCAOB risk-based approach would likely be more costly. As highlighted above, the Board expects that many firms are familiar with ISQM 1 or SQMS 1 and have made, or will make,

investments in their QC systems to comply with those requirements. Firms may be less familiar with other quality management frameworks than they are with ISQM 1 and SQMS 1. Basing QC 1000 on a different quality management framework or an original PCAOB risk-based approach therefore would likely require additional effort by firms to understand and apply the standard. Some firms may be required to employ or engage persons with the necessary expertise in the particular quality framework to facilitate appropriate implementation. While the largest firms may employ consultants with this expertise, smaller firms may not, and acquiring or engaging the necessary consultants could be costly. In addition, basing QC 1000 on a different quality management framework or an original PCAOB risk-based approach may introduce an element of regulatory complexity, which could both increase cost and detract from audit quality for firms that would be required to comply with ISQM 1 or SQMS 1.⁵¹⁸

3. Key Policy Choices

This section discusses several potential provisions that the Board decided against including in QC 1000. These provisions relate to: (1) applicability; (2) the threshold for incremental requirements; (3) firm governance structure; (4) self-assessment monitoring; (5) in-process monitoring activities; (6) the evaluation and reporting dates; (7) reporting the annual QC system evaluation; (8) certification of the annual evaluation; (9) public reporting; and (10) audit committee communications.

a. Applicability

The discussion above explains the distinction between scaled applicability and full applicability. The Board considered requiring all firms to design, implement, and operate a QC system that meets the requirements only upon being required to comply with applicable professional and legal requirements with respect to a firm

⁵¹⁸ One commenter suggested that the Board look at any lessons learned or studies published by the IAASB or the AICPA related to their quality management standards to help inform any refinements that might be needed or additional implementation guidance that might be useful for adoption of QC 1000. As discussed above, the Board took into consideration actions by other standard setters and requirements of their quality management standards in the development of QC 1000. PCAOB staff searched for studies but did not find any available. The recent effective date of ISQM 1 on Dec. 15, 2022, and the forthcoming effective date of SQMS 1 on Dec. 15, 2025, may explain a dearth of lessons learned or post-implementation studies published by IAASB or the AICPA to date.

⁵¹⁷ See, e.g., John Seddon, *Ten Arguments Against ISO 9000*, 7 *Managing Service Quality: An International Journal* 162 (1997); Bozena Poksinska, Jörgen AE Eklund, and Jens Jörn Dahlgaard, *ISO 9001:2000 in Small Organisations Lost Opportunities, Benefits and Influencing Factors*, 23 *International Journal of Quality & Reliability Management* 490 (2006).

engagement. This approach would reduce the costs of the requirements to firms not performing engagements by allowing them to defer the costs of designing their QC system. However, scaled-applicability firms may reduce their costs under the approach by withdrawing from PCAOB registration. Furthermore, any reduced costs would not address the risk that firms could be unprepared to accept and perform engagements in compliance with applicable professional and legal requirements.

The discussion above also addresses commenters' views on alternative approaches to this key policy choice. For example, several commenters suggested allowing scaled applicability firms to design a QC system that complies with ISQM 1. One commenter suggested limiting the design requirements to acceptance and continuance policies. One commenter suggested limiting the design requirement to firms that satisfy an issuer client market capitalization criterion. While these alternative approaches could reduce some of the costs to scaled-applicability firms associated with designing their QC systems, they could also reduce the benefit of firms having a PCAOB-compliant QC system ready for implementation and operation. Furthermore, as discussed above, firms could avoid the costs of designing a QC system that complies with QC 1000 by deregistering.

b. Threshold for Incremental Requirements

The incremental requirements that will apply only to firms that issued audit reports for more than 100 issuers in the prior calendar year (e.g., requirements related to firm governance structure) are discussed above. Several commenters suggested alternative thresholds. For example, some commenters suggested the threshold should consider the market capitalizations of issuer clients. One commenter suggested that the threshold should consider the types of financial statements being audited.⁵¹⁹ These alternative approaches could help ensure QC 1000 is appropriately scalable to the facts and circumstances of all firms. However, the Board believes there could be practical challenges with implementing a more complex threshold. For example, market capitalization can be volatile and would

require PCAOB and firm resources to track. Some firms may cross an issuer market capitalization threshold multiple times within a short period of time. Issuer count, by contrast, aligns with Rule 4003, *Frequency of Inspections*, is easier to track, and may not be as volatile as market capitalization. Finally, while market capitalization may be a useful proxy for investor exposure to the issuers audited by the firm, it would be a less useful proxy for the complexity of a firm's QC system.

c. Firm Governance Structure

Specified quality responses related to governance and leadership are discussed above. The Board considered extending to all firms the requirement to incorporate into their governance structure an external oversight function for the QC system composed of one or more persons who are not principals or employees of the firm and do not otherwise have a commercial, familial, or other relationship with the firm that would interfere with the exercise of independent judgment regarding matters related to the QC system. However, in light of the direct cost of such an oversight function, which could disproportionately impact smaller PCAOB audit practices, and reflecting the Board's view that the public interest in such independent oversight is strongest in relation to the largest firms, the requirement applies only to firms that issued audit reports with respect to more than 100 issuers during the prior calendar year.

Some commenters suggested that more than one independent member of the oversight function should be required. In support of this view, one commenter noted that the independent member(s) would be in the minority and cited academic research regarding audit committees that suggests oversight functions are more effective with a greater proportion of independent members.⁵²⁰ Another commenter referred to a report that cites survey research that suggests female directors improve corporate governance and that the positive influence is most significant when there are three or more female

⁵²⁰ See, e.g., F. Todd DeZoort, Dana R. Hermanson, Deborah S. Archambeault, and Scott A. Reed, *Audit Committee Effectiveness: A Synthesis of the Empirical Audit Committee Literature*, 21 *Journal of Accounting Literature* 38 (2002); Jean Bédard and Yves Gendron, *Strengthening the Financial Reporting System: Can Audit Committees Deliver?*, 14 *International Journal of Auditing* 174 (2010); Joseph V. Carcello, Dana R. Hermanson, and Zhongxia (Shelly) Ye, *Corporate Governance Research in Accounting and Auditing: Insights, Practice Implications, and Future Research Directions*, 30 *Auditing: A Journal of Practice & Theory* 1 (2011).

directors.⁵²¹ The same commenter suggested that the oversight function should have public reporting responsibilities. Some commenters suggested that the independent oversight member should have more control. The Board acknowledges the commenters' views on the potential additional benefits of additional independent oversight requirements. However, the Board is also sensitive to the costs of any additional requirements, which several commenters suggested may be costly or difficult to fulfill.⁵²²

d. Self-Assessment Monitoring

The Board considered permitting individuals to perform monitoring procedures over the same areas for which they are responsible. It decided against this approach because the Board feels it would be inconsistent with the quality objective that individuals who are assigned to perform activities within the QC system have the objectivity to monitor work in accordance with applicable professional and legal requirements and the firm's policies and procedures.⁵²³ As emphasized above, this quality objective is important for creating accountability within the firm to achieve the reasonable assurance objective. Information gathered through PCAOB inspection activities indicates that roughly 3% of firms inspected between 2018 and 2020 performed self-assessments. This suggests that relatively few firms would be impacted by this policy choice. The Board considered allowing self-assessment monitoring under certain conditions to reduce costs for impacted firms but ultimately decided against it out of concern that individuals may not be able to objectively assess their own work. In these circumstances, the firm may use other participants or third-party providers to perform monitoring activities.

e. In-Process Monitoring Activities

In-process monitoring activities are discussed above. The Board considered extending the requirement to monitor in-process engagements to all firms but decided to limit the requirement to firms that issue audit reports with respect to more than 100 issuers. The Board believes that differentiating a

⁵²¹ See The Conference Board, *Maximizing the Benefits of Board Diversity: Lessons Learned from Activist Investing* at 13 (June 2020); Alison M. Konrad, Vicki W. Kramer, and Sumru Erkut, *Critical Mass: The Impact of Three or More Women on Corporate Boards*, 37 *Organizational Dynamics* 145 (2008).

⁵²² See previous discussion on economic impacts above.

⁵²³ See QC 1000.44e.

⁵¹⁹ The commenter noted that a large percentage of their issuer audit counts consist of Form 11-K audits, which have limited impact on the capital markets.

firm's obligation based on the number of issuer clients may be appropriate because, in the Board's view, firms with larger, more complex audit practices are generally subject to quality risks for which in-process monitoring is an appropriate quality response. The Board also understands through PCAOB oversight activities that the majority of smaller PCAOB audit practices do not perform in-process monitoring activities and may lack the resources to do so. Therefore, to balance these concerns, QC 1000 includes a "should consider" requirement to provide sufficient scalability for firms that issue audit reports with respect to 100 or fewer issuers.

f. Evaluation and Reporting Dates

Several commenters suggested that QC 1000 should allow firms to choose their own evaluation date. This alternative could reduce the cost of QC 1000 by allowing firms to perform the evaluation when most convenient. For example, some firms could set their QC 1000 evaluation date near their ISQM 1 evaluation date and use parts of their ISQM 1 evaluation for their QC 1000 evaluation. However, the information reported to the PCAOB on Form QC would be less current and therefore less informative to the PCAOB when it selects firms and engagements for inspection, inspection focus areas, and inspection procedures. Tracking firms' compliance with the evaluation requirements could also be more challenging. In addition, the inherent differences between the QC 1000 and ISQM 1 evaluations will require incremental effort from firms to comply with QC 1000.

The Board initially proposed a November 30 evaluation date followed by 46 days from the evaluation date to both report and document the QC system evaluation. This timeline would provide the PCAOB with timely information to inform PCAOB oversight activities. Some commenters expressed concern that a November 30 evaluation date could present costs and other challenges because some firms have already chosen an alternative evaluation date under ISQM 1 or because the timeframe for the evaluation could conflict with some firms' inspection cycles or business cycles and can encompass holidays and religious observances. The Board was persuaded that a November 30 evaluation date could have led to unnecessary incremental resource demands during the busy and holiday seasons. Accordingly, the Board instead required firms to adopt a September 30 evaluation date as discussed above.

Some commenters expressed concern that 46 days would be insufficient to report on and document their evaluation. The Board was persuaded that 46 days to report on and document the QC system evaluation could have created unnecessary costs to firms. Therefore, under the final standard, a firm will have 61 days to evaluate their QC system and an additional 14 days after the evaluation to assemble their documentation.

g. Reporting the Annual QC System Evaluation

Firm reporting on the QC system evaluation is discussed above. One commenter asserted that an explicit reporting requirement is unnecessary because the PCAOB inspection process provides the Board and staff with any relevant contemporaneous quality control information for both annual and triennially inspected firms. The Board considered obtaining the annual QC system evaluation as part of the PCAOB inspection process rather than an explicit reporting requirement. Under this alternative approach, the evaluation would be less timely, structured, and consistent and likely would not inform the PCAOB's inspection approach as effectively, especially for triennial firms. It could also diminish the beneficial incentive effect of mandatory reporting to the PCAOB. This alternative approach could eliminate or reduce the costs to firms associated with preparing a summary report of the firm's QC system evaluation. In addition, if, under this alternative approach, the privilege protections of section 105(b)(5) were determined to apply to some or all of the information generated by the firm pursuant to QC 1000, that could diminish the discoverability of such information in litigation, thereby decreasing third-party litigation risk. However, this alternative approach would not address the lost information value, particularly for the triennial firms.

The Board also considered requiring firms to report to the Board on Form QC only when the firm identifies a major QC deficiency. This approach would reduce some of the variable costs associated with preparing and transmitting Form QC to the PCAOB. However, this approach would also reduce the value of Form QC to the PCAOB. For example, reporting on unremediated QC deficiencies would inform various aspects of PCAOB oversight activities, including focusing inspection resources on higher risk firms, engagements, and focus areas; designing the nature and extent of inspection procedures, both for QC

processes and individual engagements; and making more refined data requests from the firms. This alternative approach could also diminish the beneficial incentive effect of mandatory reporting to the PCAOB.

Several commenters suggested that the PCAOB clarify that Form QC is submitted under the PCAOB's inspections authority, as a way of bestowing the confidentiality protections of section 105(b)(5) upon the information provided therein. This would, according to commenters, alleviate uncertainty about the extent to which information submitted thereon may be subject to discovery or other disclosures, diminish a risk of unwarranted legal exposure, and help place the information in the context of the ongoing inspections dialogue. The Board acknowledges the commenters' concerns about these issues. However, as discussed above, QC 1000 is not an inspections rule; it is a QC standard that places obligations on all registered firms regardless of their inspection status (annual, triennial, or exempt), and as such the Board is not able to say that Form QC information is necessarily submitted "in connection with an inspection" as would be necessary to trigger the confidentiality protections of section 105(b)(5) of Sarbanes-Oxley.

h. Certification of the Annual Evaluation

Some commenters requested that the Board specify a heightened legal standard (e.g., recklessness) at which liability could be imposed on individuals for making a certification that is later determined to be false, or create safe harbors for inevitable system errors or the wrongful acts of others. As discussed above, the standard for liability turns on the particular language of each statement in the certification: some statements are subject to a negligence standard, while others (namely those with knowledge qualifiers) give rise to liability only if the certifier knew that the statement was false or recklessly did not know it was false. The Board acknowledges that alternative approaches urged by commenters could have saved some costs. Specifically, limiting liability to recklessness in all circumstances would provide individuals with comfort that their decisions would not be second-guessed in litigation. This result may make the performance of those services more efficient by removing an incentive to perform tasks that are not directly related to quality. For example, individuals may be less incentivized to engage in self-protective behaviors if a heightened legal standard (e.g.,

recklessness) is imposed. In addition, more staff may be willing to take these roles (or to take them at a lower price) if liability or workload would have been more limited by a heightened legal standard.⁵²⁴ However, that approach would have attenuated the benefits sought to be achieved by the certification requirement by removing the Board's ability to hold individuals accountable for conduct that fails to meet a reasonable person standard of care.

i. Public Reporting

The discussion above summarizes commenters' views on public reporting about firms' QC systems and legal constraints on public disclosure that are imposed by Sarbanes-Oxley. Some commenters suggested that the non-confidential portions of Form QC could be made publicly available. Such public reporting could in principle provide investors with additional information on audit quality and thereby help address the problem discussed above. However, the Board believes that significant portions of Form QC may be confidential. As a result, the non-confidential portions of Form QC could have been misleading and difficult to compare across firms. Public reporting of non-confidential portions of Form QC could also lead firms to be less candid in their Form QC reporting and thereby diminish its value to the PCAOB. Some commenters also expressed concern that any public reporting could be contrary to Sarbanes-Oxley. After considering the benefits and costs of alternative approaches, including those identified by commenters, the Board believes that firm reporting on Form QC should be nonpublic.

Several commenters suggested that QC 1000 should require firms to

publicly disclose information related to audit quality. As discussed above, the Board has proposed separate rules related to firm and engagement metrics as well as firm reporting.⁵²⁵

j. Audit Committee Communications

Commenters' views on potential required reporting to audit committees are discussed above. The Board initially proposed to require the firm to discuss with the audit committee the conclusion of the firm's most recent annual evaluation of its QC system and a brief overview of remedial actions taken and to be taken. This information could give audit committees greater insight into the quality of their auditor. Several commenters were supportive of the proposed requirement. However, several other commenters asserted that the information could be largely difficult to understand, irrelevant to an individual audit committee, and potentially inconsistent with Sarbanes-Oxley. Furthermore, one commenter noted research and expressed concern that disclosure regarding the annual QC system evaluation to the audit committee only could enable audit committees to shop for lower-quality auditors.⁵²⁶ Similarly, another commenter expressed concern with an approach that would provide mandatory disclosure to audit committees but not to investors and the public. As discussed above, the Board determined not to adopt the proposed amendments to AS 1301 after consideration of the comments received.

Special Considerations for Emerging Growth Companies

Pursuant to section 104 of the Jumpstart Our Business Startups ("JOBS") Act, rules adopted by the Board subsequent to April 5, 2012, generally do not apply to the audits of

emerging growth companies ("EGCs"), as defined in section 3(a)(80) of the Exchange Act, unless the SEC "determines that the application of such additional requirements is necessary or appropriate in the public interest, after considering the protection of investors and whether the action will promote efficiency, competition, and capital formation."⁵²⁷ As a result of the JOBS Act, the rules and related amendments to PCAOB standards that the Board adopts are generally subject to a separate determination by the SEC regarding their applicability to audits of EGCs.

To inform consideration of the application of PCAOB standards to audits of EGCs,⁵²⁸ PCAOB staff prepares a white paper annually that provides general information about characteristics of EGCs.⁵²⁹ As of the November 15, 2022, measurement date, there were 3,031 companies⁵³⁰ that self-identified as EGCs and filed audited financial statements with the SEC between May 16, 2021, and November 15, 2022, that included an audit report signed by a firm. Of the 263 registered firms that audited EGCs, 227 firms (or 86%) performed audits for both EGC and non-EGC issuers.⁵³¹ Approximately 98% of EGCs were audited by these 227 firms.⁵³²

PCAOB staff also gathered information on Part I.A deficiencies for the audits of EGCs between 2013 and 2022. Figure 6 presents the percentage of inspected EGC and non-EGC issuer audits having at least one Part I.A deficiency. The data suggest that Part I.A deficiencies are even more common among audits of EGCs, raising questions about whether QC systems of firms that audit EGCs are effective in preventing audit deficiencies for these types of audit engagements.

⁵²⁴ See Economic benefits—improved compliance with applicable professional and legal requirements—above for a discussion of commenters' concerns regarding increased liability or workload associated with the roles as potential disincentives that may keep qualified individuals from accepting the roles.

⁵²⁵ See PCAOB Rel. No. 2024–002 and PCAOB Rel. No. 2024–003.

⁵²⁶ See, e.g., Melissa Carlisle, Wei Yu, and Bryan K. Church, *The Effect of Small Audit Firms' Failure to Remediate the PCAOB's Quality Control Criticisms on Audit Market Segmentation*, 41 *Journal of Accounting and Public Policy* 1 (2022).

⁵²⁷ See Public Law 112–106 (Apr. 5, 2012). Section 103(a)(3)(C) of Sarbanes-Oxley, 15 U.S.C. 7213(a)(3)(C), as added by section 104 of the JOBS Act, also provides that any rules of the Board requiring (1) mandatory audit firm rotation or (2) a

supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer (auditor discussion and analysis) shall not apply to an audit of an EGC. None of the rules and amendments would fall within either of these two categories.

⁵²⁸ This analysis of the impact on EGCs is provided to assist the SEC in making the determination required under section 104 to the extent that the requirements apply to "the audit of any emerging growth company" within the meaning of section 104 of the JOBS Act.

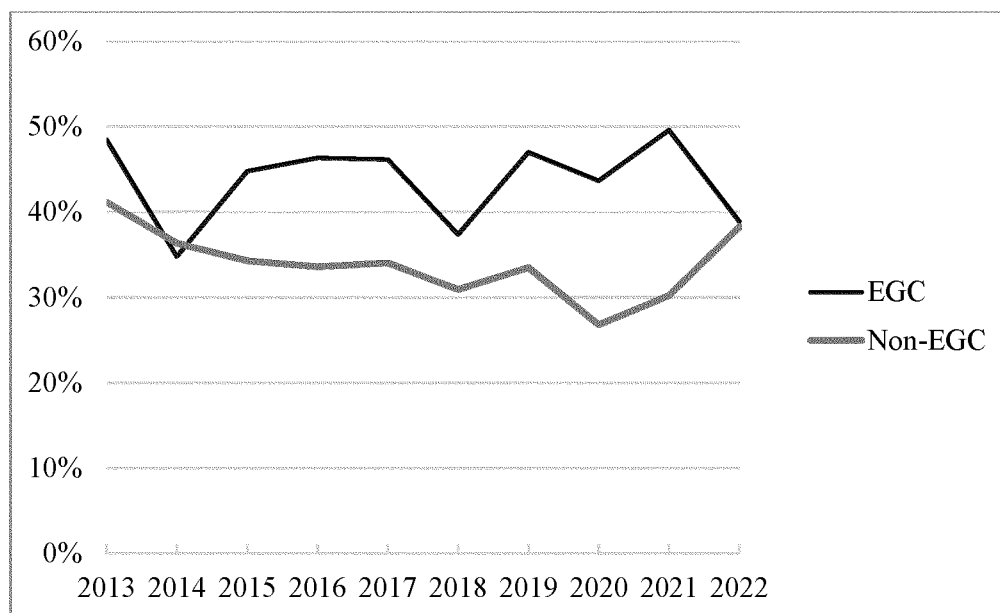
⁵²⁹ See PCAOB, *Characteristics of Emerging Growth Companies and Their Audit Firms at November 15, 2022* (Feb. 20, 2024) ("EGC White Paper"), available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/economicandriskanalysis/projects/other/documents/white-paper-on-characteristics-of-emerging-growth-companies-as-of-nov-15-2022.pdf?sfvrsn=a8294f3_2.

⁵³⁰ The EGC White Paper uses a lagging 18-month window to identify companies as EGCs. Please refer to the "Current Methodology" section in the EGC White Paper for details. Using an 18-month window enables PCAOB staff to analyze the characteristics of a fuller population in the EGC White Paper but may tend to result in a larger number of EGCs being included for purposes of the present EGC analysis than would alternative methodologies. For example, an estimate using a lagging 12-month window would exclude some EGCs that are delinquent in making periodic filings. An estimate as of the measurement date would exclude EGCs that have terminated their registration or that have exceeded the eligibility or time limits.

⁵³¹ See EGC White Paper, at 17.

⁵³² See *id.*

Figure 6. Percentage of Inspected EGC and Non-EGC Issuer Audits Having at Least One Part I.A Deficiency (2013-2022)



In general, any new PCAOB standards and amendments to existing standards determined not to apply to the audits of EGCs would require auditors to address differing requirements within their methodologies or policies and procedures with respect to audits of EGCs and non-EGCs, which would create the potential for confusion. This may not be practical in the context of the QC standards; while some components of the QC system (such as engagement monitoring) may enable different approaches for audits of EGCs compared to audits of other companies, other elements (for example, resources and governance and leadership) are necessarily firm-wide and cannot easily be differentiated for different types of audits. Even where differentiation is possible, maintaining separate QC system components for EGC and non-EGC audits and separate methodologies with respect to, for example, auditor obligations with respect to deficiencies in completed engagements and foundational ethics requirements, may add cost or lead to confusion, and could run counter to the objective of integrating QC practices into a single virtuous cycle of risk assessment, monitoring, and remediation. These methodology and QC system differentiation costs would affect at least the 227 registered firms that audit both EGCs and non-EGCs and that, collectively, audit approximately 98% of EGCs.

The discussion of economic impacts of the requirements is generally

applicable to the audits of EGCs. In particular, the benefits to financial reporting quality articulated above may be especially pertinent for EGCs, including improved efficiency of capital allocation, lower cost of capital, and enhanced capital formation. EGCs tend to be smaller⁵³³ and have a shorter SEC financial reporting history than the broader population of public companies. Academic research suggests that, for several reasons, smaller public companies tend to exhibit greater information asymmetry between management and investors.⁵³⁴ Accordingly, EGCs are likely to exhibit greater information asymmetry between management and investors and hence the importance of the external audit to investors in enhancing the credibility of EGC financial reporting may be more pronounced.

The requirements could impact competition in an EGC product market if the indirect costs to audited companies of the requirements disproportionately impact the EGCs relative to their competitors. EGCs may be forced to raise prices, thereby

diverting market share toward their competitors. This could increase competition in markets where EGCs have a dominant market share and decrease competition in markets where EGCs have a less than dominant market share. The potential impact to competition in EGC product markets would be reduced to the extent EGC auditors will already be required to comply with ISQM 1 or SQMS 1 or otherwise would choose not to pass on incremental costs arising from the requirements in the form of higher audit fees.

The proposal sought comment on the applicability of the proposed requirements to audits of EGCs. Some commenters agreed that the proposed requirements should apply to the audits of EGCs.

Accordingly, and for the reasons explained above, the Board requests that the Commission determine that it is necessary or appropriate in the public interest, after considering the protection of investors and whether the action will promote efficiency, competition, and capital formation, to apply QC 1000 and the related amendments to Board standards, rules, and forms to audits of EGCs.

III. Date of Effectiveness of the Proposed Rules and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to

⁵³³ See EGC White Paper, at Figure 9 and Figure 12 (indicating that exchange-listed EGCs have lower market capitalization and revenue than exchange-listed non-EGCs).

⁵³⁴ For example, smaller public companies tend to have less analyst coverage and a greater share of insider holdings. See, e.g., Raymond Chiang and P. C. Venkatesh, *Insider Holdings and Perceptions of Information Asymmetry: A Note*, 43 *Journal of Finance* 1041 (1988); Ravi Bhushan, *Firm Characteristics and Analyst Following*, 11 *Journal of Accounting and Economics* 255 (1989).

90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding; or (ii) as to which the Board consents, the Commission will:

(A) By order approve or disapprove such proposed rules; or

(B) Institute proceedings to determine whether the proposed rules should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views and arguments concerning the foregoing, including whether the proposed rules are consistent with the requirements of Title I of 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/pcaob>); or
- Send an email to rule-comments@sec.gov. Please include PCAOB-2024-02 on the subject line.

Paper Comments

- Send paper comments in triplicate to Vanessa A. Countryman, Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549-1090.

All submissions should refer to PCAOB-2024-02. 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/pcaob>). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rules that are filed with the Commission, and all written communications relating to the proposed rules 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 a.m. and 3 p.m. Copies of such filing will also be available for inspection and copying at the principal office of the PCAOB. 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 PCAOB-2024-02 and should be submitted on or before July 2, 2024.

For the Commission, by the Office of the Chief Accountant.⁵³⁵

Vanessa A. Countryman,
Secretary.

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⁵³⁵ 17 CFR 200.30-11(b)(1) and (3).



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Public Company Accounting Oversight Board; Notice of Filing of Proposed Rules on General Responsibilities of the Auditor in Conducting an Audit and Amendments to PCAOB Standards; Notice

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34-100276; File No. PCAOB-2024-01]

Public Company Accounting Oversight Board; Notice of Filing of Proposed Rules on General Responsibilities of the Auditor in Conducting an Audit and Amendments to PCAOB Standards

June 5, 2024

Pursuant to Section 107(b) of the Sarbanes-Oxley Act of 2002 (“Sarbanes-Oxley,” or the “Act”), notice is hereby given that on May 24, 2024, the Public Company Accounting Oversight Board (the “Board” or the “PCAOB”) filed with the Securities and Exchange Commission (the “Commission” or the “SEC”) the proposed rules described in items I and II below, which items have been prepared by the Board. The Commission is publishing this notice to solicit comments on the proposed rules from interested persons.

I. Board’s Statement of the Terms of Substance of the Proposed Rules

On May 13, 2024, the Board adopted *General Responsibilities of the Auditor in Conducting an Audit and Amendments to PCAOB Standards* (“proposed rules”). The text of the proposed rules appears in Exhibit A to the SEC Filing Form 19b-4 and is available on the Board’s website at <https://pcaobus.org/about/rules-rulemaking/rulemaking-dockets/docket-049-responsibilities-auditor-conducting-audit>, and at the Commission’s Public Reference Room.

II. Board’s Statement of the Purpose of, and Statutory Basis for, the Proposed Rules

In its filing with the Commission, the Board included statements concerning the purpose of, and basis for, the proposed rules and discussed any comments it received on the proposed rules. The text of these statements may be examined at the places specified in Item IV below. The Board has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements. In addition, the Board is requesting that the Commission approve the proposed rules, pursuant to Section 103(a)(3)(C) of the Act, for application to audits of emerging growth companies (“EGCs”), as that term is defined in Section 3(a)(80) of the Securities Exchange Act of 1934 (“Exchange Act”). The Board’s request is set forth in section D.

A. Board’s Statement of the Purpose of, and Statutory Basis for, the Proposed Rules

(a) Purpose

The Board adopted a new auditing standard, AS 1000, *General Responsibilities of the Auditor in Conducting an Audit* (“new standard,” “final standard,” or “AS 1000”). The new standard replaces a group of standards originally developed by the American Institute of Certified Public Accountants (“AICPA”) and adopted on an interim basis by the PCAOB in 2003. That group of standards established the general principles and responsibilities of the auditor when conducting an audit (“foundational standards”). The general principles and responsibilities addressed by the foundational standards include reasonable assurance, due professional care, professional skepticism, independence, competence, and professional judgment. These principles and related responsibilities provide a foundation for the proper performance of the audit.

Through this standard-setting project, the Board has reaffirmed the general principles and responsibilities of the auditor so that the foundation underlying the standards continues to be sound and appropriate for performing high-quality audits. These principles and responsibilities, enhanced and consolidated into a single auditing standard, together with related amendments, will modernize the auditing standards to better address fundamental aspects of the audit and provide auditors with better direction to protect investors and further the public interest in the preparation of informative, accurate, and independent auditor’s reports.

AS 1000 will replace four standards that set forth the general principles and responsibilities of the auditor: AS 1001, *Responsibilities and Functions of the Independent Auditor*; AS 1005, *Independence*; AS 1010, *Training and Proficiency of the Independent Auditor*; and AS 1015, *Due Professional Care in the Performance of Work*. AS 1000 combines and updates the general principles and responsibilities of these standards to reflect developments in the auditing environment.

The Board also amended certain other standards that address responsibilities fundamental to the conduct of an audit. These amendments clarify the engagement partner’s responsibility to exercise due professional care related to supervision and review of the audit, accelerate the documentation completion date by reducing the maximum period for the auditor to

assemble a complete and final set of audit documentation from 45 days to 14 days, and clarify the auditor’s responsibility to evaluate whether the financial statements are “presented fairly.” Finally, the Board adopted additional amendments to conform to these changes.

After carefully considering the comments the Board received, the Board adopted the amendments substantially as proposed, with revisions that reflect the input of commenters.

Since the PCAOB’s adoption of the foundational standards in 2003, the auditing environment has evolved, including:

- Changes to auditing requirements through Board-issued standards;
- New or revised independence requirements issued by the Board; and
- Advancements in technology that are increasing the availability of electronic audit tools and use of audit software.

The new standard and related amendments the Board adopted will modernize PCAOB standards to:

- Reflect changes in the auditing environment;
- Eliminate outdated and inconsistent language; and
- Achieve consistency with Board-issued standards.

AS 1000 and the related amendments modernize, clarify, and streamline the general principles and responsibilities of the auditor and provide a more logical presentation, which should enhance the useability of the standards by making them easier to read, understand, and apply.

The Board clarified the auditor’s responsibility to evaluate whether the financial statements are “presented fairly.” The Board also clarified the engagement partner’s due professional care responsibilities by adding specificity to certain audit performance principles set out in the standards. Finally, the accelerated documentation completion date reflects changes in the auditing environment, including advancements in technology that have enabled auditors to assemble a complete and final set of audit documentation in less time than in a paper-based environment. The new documentation completion date reduces the window of opportunity for improper alteration of audit documentation and also enables the Board to potentially begin the inspection process sooner after completion of an audit, which the Board believes can enhance the Board’s efforts to improve audit quality and promote investor protection, ultimately enhancing investor confidence.

The new standard and related amendments will apply to all audits conducted under PCAOB standards.

See Exhibit 3 for additional discussion of the purpose of this project.

(b) Statutory Basis

The statutory basis for the proposed rules is Title I of the Act.

B. Board's Statement on Burden on Competition

Not applicable. The Board's consideration of the economic impacts of the proposed rules is discussed in section D below.

C. Board's Statement on Comments on the Proposed Rules Received From Members, Participants or Others

The Board initially released the proposed rules for public comment in PCAOB Release No. 2023-001 (Mar. 28, 2023). The Board received 28 written comment letters that were specifically submitted in response to its initial proposed rules in PCAOB Release No. 2023-001. In addition, the Board received six comment letters relating to its consideration of proposed amendments on quality control, which were released for public comment on November 19, 2022, and that are relevant to the definition of "applicable professional and legal requirements" in these proposed rules. See Exhibits 2(a)(B) and 2(a)(C). The Board has carefully considered all comments received. The Board's response to the comments it received, and the changes made to the rules in response to the comments received are discussed below.

Background

In April 2003, the Board adopted, on an interim basis, the generally accepted auditing standards of the AICPA's Auditing Standards Board ("interim standards") and the related auditing interpretations as they existed then.¹ At that time, the Board stated that it would determine whether the interim standards "should become permanent standards of the Board, should be repealed, or should be modified."² Since then, the Board has adopted a number of new auditing standards that supersede or amend portions of the interim standards and related auditing interpretations.³ However, certain

remaining interim standards, including those that address the general principles and responsibilities of the auditor, have continued to be in effect substantially in the form adopted.

Since the adoption of the interim standards, the auditing environment has evolved in many ways, including (i) changes to auditing requirements through Board-issued standards; (ii) new or revised independence requirements issued by the Board;⁴ and (iii) advancements in technology that are increasing the availability of electronic audit tools and the use of audit software. While these developments have generally been reflected through amendments to some interim standards and related interpretations in connection with the Board's standard-setting initiatives, the 2022-2026 Strategic Plan reinforced the Board's intent "to modernize and streamline [the Board's] existing standards and to issue new standards where necessary to meet today's needs" as part of the PCAOB's investor protection mission.⁵

In connection with these initiatives,⁶ the Board analyzed the interim foundational standards that address the general principles and responsibilities of the auditor in conducting an audit. These foundational standards are:

- AS 1001, *Responsibilities and Functions of the Independent Auditor*;
- AS 1005, *Independence*;
- AS 1010, *Training and Proficiency of the Independent Auditor*; and
- AS 1015, *Due Professional Care in the Performance of Work*.⁷

The general principles and responsibilities addressed by the foundational standards include

Results, and AS 3101, *The Auditor's Report on an Audit of Financial Statements When the Auditor Expresses an Unqualified Opinion*.

⁴ See generally Section 3 of PCAOB rules, *Auditing and Related Professional Practice Standards*, Part 5, *Ethics and Independence*.

⁵ See PCAOB, *Strategic Plan 2022-2026*, at 10, available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/about/administration/documents/strategic_plans/strategic-plan-2022-2026.pdf?sfvrsn=b2ec4b6a_4/.

⁶ See PCAOB's interim standards project, available at <https://pcaobus.org/oversight/standards/standard-setting-research-projects/interim-standards>.

⁷ When adopted by the Board in 2003, this group of interim standards was designated as AU sec. 110, AU sec. 220, AU sec. 210, and AU sec. 230. In 2015, the PCAOB reorganized its auditing standards using a topical structure and a single, integrated number system, and these interim standards were designated as AS 1001, AS 1005, AS 1010, and AS 1015, respectively. See *Reorganization of PCAOB Auditing Standards and Related Amendments to PCAOB Standards and Rules*, PCAOB Rel. No. 2015-002 (Mar. 31, 2015). The reorganization did not impose additional requirements on auditors or change substantively the requirements of PCAOB standards.

reasonable assurance, due professional care, professional skepticism, independence, competence, and professional judgment. Through this rulemaking, the Board is reaffirming and modernizing the general principles and responsibilities of the auditor to ensure that the foundation continues to be sound and appropriate for performing high-quality audits.

Rulemaking History

In March 2023, the Board proposed a new, single standard to replace the foundational standards that address the general principles and responsibilities of the auditor in conducting an audit ("proposed standard").⁸ The proposal also included key amendments to other PCAOB standards that address matters that are fundamental to the conduct of an audit. These proposed amendments clarified the engagement partner's responsibility to exercise due professional care related to supervision and review of the audit, accelerated the documentation completion date by reducing the maximum period for the auditor to assemble a complete and final set of audit documentation from 45 days to 14 days, and clarified the auditor's responsibility to evaluate whether the financial statements are "presented fairly."

The Board received 28 comment letters on the proposal.⁹ Commenters included investor-related groups, firms, firm-related groups, academics, and others. The Board considered all comments in developing the final standard and amendments, and specific comments are discussed in the analysis that follows.

Overview of Existing Requirements

This section discusses key provisions of the existing standards.

Key provisions of AS 1001, *Responsibilities and Functions of the Independent Auditor*, include:

- The objective of an audit of financial statements is to express an opinion on the fairness of the financial statements in presenting, in all material respects, the financial position, results of operations, and cash flows in accordance with generally accepted accounting principles ("GAAP"). The

⁸ Proposed Auditing Standard—General Responsibilities of the Auditor in Conducting an Audit and Proposed Amendments to PCAOB Standards, PCAOB Rel. No. 2023-001 (Mar. 28, 2023) ("proposal" or "proposing release").

⁹ The comment letters received on the proposal are available in the docket for this rulemaking on the PCAOB's website (<https://pcaobus.org/about/rules-rulemaking/rulemaking-dockets/docket-049-responsibilities-auditor-conducting-audit/comment-letters>).

¹ See *Establishment of Interim Professional Auditing Standards*, PCAOB Rel. No. 2003-006 (Apr. 18, 2003). The auditing interpretations were the publications entitled "Auditing Interpretations" issued by the AICPA Auditing Standards Board, as they existed and were effective as of April 2003.

² See PCAOB Rel. No. 2003-006.

³ See, e.g., AS 1201, *Supervision of the Audit Engagement*; AS 1215, *Audit Documentation*; AS 2101, *Audit Planning*; AS 2810, *Evaluating Audit*

auditor also disclaims an opinion if circumstances require. (AS 1001.01)

- The responsibilities of the auditor and management are that (i) the auditor plans and performs the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether caused by error or fraud; and (ii) management is responsible for the financial statements, including adopting accounting policies and establishing and maintaining internal control to initiate, record, process, and report transactions (as well as events and conditions) consistent with management's assertions in the financial statements. (AS 1001.02–.03)

- The auditor is to possess professional qualifications and exercise professional judgment in determining which auditing procedures are necessary in the circumstances to gain a reasonable basis for the opinion. (AS 1001.04–.05)

- The auditor should be aware of and consider auditing interpretations applicable to the audit and, if the guidance in the interpretations is not followed, be prepared to explain how the auditor complied with the provisions of the auditing standard addressed by the guidance. (AS 1001.11)

Key provisions of AS 1005, *Independence*, require that the auditor:

- Maintain independence in mental attitude and be intellectually honest, impartial, and without bias with respect to the client (*i.e.*, be independent in fact). (AS 1005.01–.03)
- Be free from any obligation to or interest in the client, its management, or its owners, so that the general public maintains confidence in the independence of auditors. (AS 1005.03)
- Not only be independent in fact, but also avoid situations that may lead outsiders to doubt the auditor's independence. (AS 1005.03)

Key provisions of AS 1010, *Training and Proficiency of the Independent Auditor*, require that:

- The audit be performed by persons having adequate technical training, proficiency, and experience as an auditor. (AS 1010.01–.02)
- The training of the auditor be adequate to meet the requirements of the profession, be adequate in technical scope, and include general education. (AS 1010.01–.03)
- New audit professionals obtain professional experience through proper supervision and review of their work by those who are more experienced, with the nature and extent of supervision reflecting variances in practice. (AS 1010.03)
- The engagement partner exercise seasoned judgment in the varying

degrees of supervision and review of work performed and judgments exercised by subordinates, and subordinates meet the responsibilities of their work. (AS 1010.03)

- The auditor continue professional training to become aware of developments in business and the profession, and study, understand, and apply new pronouncements on accounting and auditing. (AS 1010.04)

Key provisions of AS 1015, *Due Professional Care in the Performance of Work*, require that:

- The auditor exercise due professional care in the planning and performance of the audit and the preparation of the report, including observance of the auditing standards by professionals within the auditor's organization. (AS 1015.01–.02)
- The auditor possess “the degree of skill commonly possessed” by other auditors and exercise it with “reasonable care and diligence” (*i.e.*, due professional care) in the planning and performance of the audit and the preparation of the report. (AS 1015.01 and .05)

- The engagement team be assigned to tasks and be supervised commensurate with their level of knowledge, skill, and ability so that they can evaluate the audit evidence they are examining. (AS 1015.06)

- The engagement partner know, at a minimum, the relevant professional accounting and auditing standards, be knowledgeable of the audit client, and be responsible for the assignment of tasks to, and supervision of, the members of the engagement team. (AS 1015.06)

- The auditor exercise professional skepticism throughout the audit, with a questioning mind and a critical assessment of audit evidence, to diligently gather and objectively evaluate audit evidence, and consider the competency and sufficiency of the evidence, and not be satisfied with less than persuasive evidence because of a belief that management is honest. (AS 1015.07–.09)

- The auditor obtain reasonable assurance about whether the financial statements are free of material misstatement, whether caused by error or fraud, or whether any material weaknesses exist as of the date of management's assessment. Reasonable assurance is “a high level of assurance” but is not absolute assurance because of the nature of audit evidence and the characteristics of fraud. (AS 1015.10)

Key provisions of other standards relevant to this rulemaking include:

- AS 1201.04–.05 and AS 2101.03, which describe the engagement

partner's responsibilities for supervision and review of audit documentation.

- AS 1215.06, which requires the auditor to document procedures performed, evidence obtained, and conclusions reached with respect to relevant financial statement assertions.

- AS 1215.15, which requires the auditor to complete the necessary auditing procedures and assemble for retention a complete and final set of audit documentation within 45 days after the report release date.

- AS 2810.30, which requires the auditor to evaluate whether the financial statements are presented fairly, in all material respects, in conformity with the applicable financial reporting framework.

- AS 2815, *The Meaning of “Present Fairly in Conformity with Generally Accepted Accounting Principles,”* which explains the meaning of “present fairly” as used in the phrase “present fairly . . . in conformity with generally accepted accounting principles,” and the basis for the auditor's opinion on whether the financial statements present fairly an entity's financial position, results of operations, and cash flows in conformity with generally accepted accounting principles.

Reasons To Improve Auditing Standards

The new standard and related amendments are intended to modernize, clarify, and streamline the general principles and responsibilities of the auditor described in the foundational standards. The Board identified several areas discussed below that the Board believes will enhance the useability of the requirements by making them easier to read, understand, and apply.

1. Alignment With Board-Issued Standards and Rules

Since the adoption of the foundational standards, the Board has issued a number of new auditing standards and amendments. Certain of these standards address other principles and responsibilities that are fundamental to the conduct of an audit, including the engagement partner's supervisory and review responsibilities and general requirements for audit documentation. Expressly incorporating these specific principles and responsibilities for conducting an audit in the new standard and related amendments should provide the auditor with more complete direction on matters that are central to the auditor's work.

Certain descriptions of requirements in the foundational standards do not align with the language used in Board-issued standards. For example, some

provisions in the foundational standards refer to GAAP;¹⁰ however, in recognition of the SEC's acceptance of filings that include financial statements prepared under accounting frameworks other than U.S. GAAP, such as International Financial Reporting Standards ("IFRS"), Board-issued standards are written as framework neutral and refer instead to the applicable financial reporting framework.¹¹ As another example, in describing professional skepticism, AS 1015 refers to the competency and sufficiency of the audit evidence rather than using terminology consistent with the Board-issued AS 1105, *Audit Evidence*, which refers to audit evidence as sufficient and appropriate. The Board believes that aligning the descriptions of the general principles and responsibilities in the new standard with language used in Board-issued standards will minimize potential confusion.

The foundational standards were originally written for audits of financial statements, but certain general principles and responsibilities described in the standards (e.g., reasonable assurance, due professional care, and professional skepticism) apply equally to audits of internal control over financial reporting ("ICFR"). None of the foundational standards mention audits of ICFR or refer to AS 2201, *An Audit of Internal Control Over Financial Reporting That Is Integrated with An Audit of Financial Statements*. While AS 2201 refers to the foundational standards for the requirements related to technical training and proficiency as an auditor, independence, and the exercise of due professional care, including professional skepticism,¹² the Board believes it is important to clarify in the new standard that the general principles and responsibilities apply to an audit of ICFR as well as an audit of financial statements.

The application of the general principles and responsibilities should be improved by conforming the presentation of the related requirements to the structure used in Board-issued standards. This includes specifying an

introduction and objectives to the new standard. In addition, the responsibilities from the foundational standards should be clarified by expressing the related requirements using terms described in PCAOB Rule 3101, *Certain Terms Used in Auditing and Related Professional Practice Standards* (e.g., using "must" and "should" to describe the degree of responsibility that the standards impose on auditors). Much of the explanatory material from the foundational standards that continues to be relevant has been relocated to the discussion in this release, which should facilitate the auditor's navigation of the relevant requirements and align with the approach taken in Board-issued standards.

2. New or Revised Independence Requirements Issued by the PCAOB and the SEC

Since the adoption of AS 1005 in 2003, the PCAOB has issued independence rules that have imposed certain incremental independence requirements on firms, relative to the SEC rules¹³ (e.g., provisions related to tax services for persons in financial reporting oversight roles at issuer audit clients).¹⁴ These incremental independence requirements are not expressly addressed in AS 1005, but nevertheless the auditor is required to comply with them. Further, while AS 1005 includes a general reference to the SEC's requirements for auditor independence, there is no reference to the specific requirements. The Board believes it is helpful to refer explicitly in the new standard to the requirements that govern auditor independence, including independence requirements set out by the federal securities laws and related rules, which include an overarching provision for the auditor to maintain independence from its client in fact and in appearance.¹⁵

3. Advancements in Technology Increasing the Availability of Electronic Audit Tools and Use of Audit Software

Since the foundational standards were adopted by the PCAOB, advancements in technology have increased the availability of electronic audit tools and use of audit software. Auditors have largely moved away from a paper-based approach to audit documentation in

favor of using software that houses electronic workpapers and audit programs. Use of electronic workpapers facilitates more efficient performance and review of audit procedures and enables auditors to assemble a complete and final set of audit documentation in less time than in a paper-based environment.

Auditors are also expanding their use of and reliance on electronic audit tools. For example, some firms have made significant investments in internally developed tools for use in the audit. In addition, some "off-the-shelf" applications such as data analysis software have become available to auditors. These advancements have changed the way that many auditors perform and document their audit procedures and retain related audit documentation. Accordingly, the new standard and amendments reflect an accelerated documentation completion date and related documentation requirements.

4. Outdated and Inconsistent Language

The foundational standards include outdated and inconsistent language that is not relevant to audits conducted under the standards of the PCAOB. For example, paragraph .03 of AS 1001 provides that the auditor may draft the financial statements in whole or in part based on information from management during performance of the audit. This provision is outdated and should not be included in PCAOB auditing standards because an auditor drafting the financial statements would violate the applicable independence rules.¹⁶ Eliminating outdated language used in the foundational standards should remove inconsistencies between PCAOB auditing standards and the relevant rules of the PCAOB and the SEC. Similarly, in describing the objective of the audit, paragraph .01 of AS 1001 refers to financial position, results of operations, and cash flows. This language could be unnecessarily limiting because the objective of the audit does not change based on the subject matter of the audit (e.g., whether it is an audit of ICFR or the financial statements). The new standard excludes references that are outdated or inconsistent, which the Board believes improves the application of the requirements and provides clearer direction to auditors in executing their responsibilities.

¹⁰ See, e.g., AS 1001.01 and .03.

¹¹ See paragraph .01, footnote 1 of AS 2410, *Related Parties* ("The auditor should look to the requirements of the U.S. Securities and Exchange Commission for the company under audit with respect to the accounting principles applicable to that company . . ."); *Auditing Standard No. 18—Related Parties Amendments to Certain PCAOB Auditing Standards Regarding Significant Unusual Transactions and Other Amendments to PCAOB Auditing Standards*, PCAOB Rel. No. 2014-002 (June 10, 2014), at A4-6 (describing the approach of AS 2410.01, footnote 1 as "framework neutral").

¹² See AS 2201.04.

¹³ See generally PCAOB rules under Section 3. Auditing and Related Professional Practice Standards, Part 5—Ethics and Independence.

¹⁴ See PCAOB Rule 3523, Tax Services for Persons in Financial Reporting Oversight Roles.

¹⁵ See Section 10A(g) of the Securities Exchange Act of 1934 ("the Exchange Act"), 15 U.S.C. 78j-1(g); 17 CFR 210.2-01 (Regulation S-X Rule 2-01).

¹⁶ See 17 CFR 210.2-01(c)(4)(i) (Regulation S-X Rule 2-01(c)(4)(i)).

5. Activities of Other Standard Setters

Since the Board's adoption of the foundational standards, both the International Auditing and Assurance Standards Board ("IAASB") and the Auditing Standards Board ("ASB") of the AICPA have updated their analogous standards:

- IAASB Standard—International Standard on Auditing 200, *Overall Objectives of the Independent Auditor and the Conduct of an Audit in Accordance with International Standards on Auditing* ("ISA 200") (effective 2009); and
- ASB Standard—AU-C Section 200, *Overall Objectives of the Independent Auditor and the Conduct of an Audit in Accordance With Generally Accepted Auditing Standards* ("AU-C 200") (effective 2012).

These revisions were part of clarity projects that were designed to make the standards easier to read, understand, and apply.¹⁷ These standards were updated to align the terminology used throughout the standards for consistency and to enhance and update explanatory materials.

6. Comments on Reasons for Standard Setting and Proposed Approach

The proposal sought comment on the appropriateness of the general principles and responsibilities of the auditor and the approach to reorganize and consolidate those responsibilities. Commenters who responded generally agreed that the general principles and responsibilities (*i.e.*, reasonable assurance, due professional care, professional skepticism, independence, competence, and professional judgment) described in the proposal are appropriate. One commenter suggested that the Board address the relevance and reliability of audit evidence and information in conjunction with the requirements in AS 1105, as part of the general principles and responsibilities. Some commenters addressed the reorganization and consolidation of the four existing foundational standards into one new standard and generally supported the proposed approach.

Commenters were generally supportive of the Board's efforts to modernize and streamline the general principles and responsibilities of the auditor. Several commenters, for example, agreed that the proposed standard would provide a more logical presentation, which would enhance the

useability of the standards by making them easier to read, understand, and apply. Some commenters, including investor-related groups, also expressed support for the proposal's focus on investor protection.

Two commenters suggested consideration of analogous standards of the IAASB and the ASB. One commenter stated that PCAOB auditing standards should not diverge from AICPA auditing standards, to the extent appropriate. Another commenter recommended that the Board consider similar standards of the IAASB and the ASB and assess whether their approach could result in higher quality audits.

The proposal also sought comment on the appropriateness of the general principles and responsibilities of the auditor in light of the availability of electronic audit tools and the use of audit software by both larger and smaller firms. Most commenters did not address this question. One commenter agreed that the proposed general principles and responsibilities of the auditor are appropriate and clear because they are necessary to the audit regardless of electronic tools and audit software. Another commenter recommended considering future possibilities and uses of machine learning and artificial intelligence ("AI") technologies, which in the views of the commenter "are progressing rapidly."

The final standard retains the general principles and responsibilities of the auditor described in the proposal, subject to revisions described below. The final standard also retains the overall approach of consolidating the foundational standards and the general principles and responsibilities of the auditor under one standard. The Board did not add specific requirements for evaluating the relevance and reliability of audit evidence, as suggested by one commenter, because AS 1105 provides the necessary framework for this evaluation. The final standard includes general requirements for conducting an audit, and obtaining sufficient appropriate audit evidence is part of those general requirements.

In addition, in the final standard the Board did not add provisions specific to the current and future use of emerging technologies. Due to the ever-evolving nature of technology, specifying requirements for certain types of technology based on how those tools are used today could quickly make the standard become outdated. Further, the general principles and responsibilities addressed in the standard apply to all audits, irrespective of the technology that may be used in performing audit

procedures. The Board continues to address emerging technologies (*e.g.*, machine learning and AI) as part of the staff's ongoing Data and Technology research project.¹⁸ Research from this project may give rise to individual standard-setting projects and may also inform the scope or nature of other projects that are included on the Board's standard-setting agenda.

With respect to comments on analogous standards issued by other standard setters, the Board believes that AS 1000 is based on general principles and responsibilities of the auditor, similar to the bases of analogous IAASB and AICPA standards. The Board carefully considered the approaches of other standard setters when developing the proposal, and the new standard and amendments being adopted reflect the approach that the Board believes best protects investors and furthers the public interest. As a result, certain differences exist between the Board's new standard and those of other standard setters, including a number of provisions that the Board believes are appropriate and consistent with the Board's statutory mandate to protect the interests of investors and further the public interest.

Discussion of Final Rules

A. Overview of Final Rules

The Board replaced AS 1001, AS 1005, AS 1010, and AS 1015 with one standard, AS 1000, that describes the general principles and responsibilities of an auditor¹⁹ in conducting an audit in accordance with the standards of the PCAOB. Briefly, the new standard:

- Includes introductory language that reaffirms the auditor's fundamental obligation to protect investors through the preparation and issuance of informative, accurate, and independent auditor's reports;
- Includes objectives for the auditor to conduct and communicate the results of both an audit of a company's financial statements and an audit of a company's ICFR and satisfy and fulfill other general principles and responsibilities described in this standard;

¹⁸ See the PCAOB's agenda related to standard setting, research, and rulemaking projects, available at <https://pcaobus.org/oversight/standards/standard-setting-research-projects>.

¹⁹ The term "auditor" includes both a public accounting firm registered with the PCAOB and associated persons thereof, as defined in PCAOB Rule 1001, *Definitions of Terms Employed in Rules*. For example, engagement quality reviewers ("EQRs"), by virtue of their status as associated persons, are within the term "auditor" in AS 1000. See also paragraph .03 of AS 1220, *Engagement Quality Review*.

¹⁷ Descriptions of the clarity projects of the IAASB and ASB are available, respectively, at <https://www.iaasb.org/projects/clarity-iaasb-standards> and <https://us.aicpa.org/interestareas/frc/auditattest/improvingclarityasbstandards>.

- Retains and clarifies the general principles and responsibilities that are important for an audit, including reasonable assurance, due professional care, professional skepticism, and professional judgment;

- Aligns the engagement partner's supervisory responsibilities under AS 1201 with due professional care;

- Retains the requirement for the auditor to be independent but expresses the obligation more directly by referring to the PCAOB's independence criteria in its rules and standards, and the independence criteria set out in the rules and regulations of the SEC;

- Describes the auditor's obligations to (i) comply with ethics requirements, (ii) obtain and maintain competence, and (iii) prepare audit documentation;

- Expresses the auditor's responsibilities by using the terms set forth in PCAOB Rule 3101 (*e.g.*, must and should) that describe the degree of responsibility that PCAOB standards impose on auditors; and

- Removes language that is outdated, inconsistent, and not relevant to audits conducted under the standards of the PCAOB.

As previously noted, the Board amended other PCAOB auditing standards that address responsibilities fundamental to the conduct of an audit to:

- Clarify the engagement partner's existing responsibilities for supervision and review in AS 1201, AS 1215, and AS 2101 to provide more specificity about the engagement partner's responsibility to exercise due professional care related to supervisory and review activities required to be performed under existing auditor requirements;

- Clarify the requirements for audit documentation in AS 1215 to identify who performed the work, who reviewed the work, and the date of such review;

- Accelerate the period in AS 1215 to assemble a complete and final set of audit documentation for retention from 45 days to 14 days; and

- Update and incorporate the underlying requirements of AS 2815 into AS 2810, and rescind AS 2815, while preserving the meaning of "present fairly" and streamlining the requirements to provide a more logical presentation.

In a separate release, the Board is also adopting a new quality control standard, QC 1000, *A Firm's System of Quality Control*, and a new ethics standard, EI 1000, *Integrity and Objectivity*, together with other amendments to PCAOB

standards, rules, and forms.²⁰ This release includes references to QC 1000 and EI 1000, where appropriate.

B. AS 1000

1. Introduction

See Paragraphs .01 Through .02 of the New Standard.

The first paragraph of the proposed standard, under the heading "Introduction," described the fundamental obligation of auditors to protect investors through the preparation and issuance of informative, accurate, and independent auditor's reports. It noted that an audit primarily benefits investors who rely on the audit to provide objective and independent opinions on whether the company's financial statements are presented fairly and, if applicable, on the effectiveness of the company's ICFR. The proposed paragraph further provided that a properly conducted audit and related auditor's report enhance the confidence of investors and other market participants in the company's financial statements and, if applicable, ICFR. The existing foundational standards do not include an introduction and do not describe the auditor's fundamental responsibility to protect investors.

Investor-related groups strongly supported the proposed standard's emphasis on the auditor's obligation to protect investors. These commenters suggested some clarification in the language describing the auditor's obligation for, and role in, protecting investors, as described in the Supreme Court opinion in *United States v. Arthur Young & Co.*²¹ Some pointed to, for example, language stating that the auditor "assumes a *public* responsibility transcending any employment relationship with the client" and that the auditor "owes ultimate allegiance to the corporation's creditors and stockholders, as well as the investing public."²² One of these commenters stated that without additional clarification, the phrase "fundamental obligation" is a vague concept and open to interpretation. Two commenters recommended including in AS 1000 a footnote from the proposal that cites the *Arthur Young* opinion.

Two commenters, including an investor-related group, recommended that the standard's reference to investors be broadened to include shareholders, debtholders, and other financial

statement users who rely on a company's financial statements, consistent with the usage by Financial Accounting Standards Board ("FASB") and the Supreme Court in the *Arthur Young* opinion. One of these commenters recommended including a definition of "financial statement users" in the final standard. Another recommended adding a footnote to the first sentence of paragraph .01 defining and describing the meaning of "investors."

A number of other commenters, primarily firms, expressed concerns that the introduction language describing the auditor's role was unclear and could be misleading. For example, several commenters noted that the description of the auditor's role in protecting investors could be viewed as creating a new legal obligation owed to investors. In the view of one commenter, the proposed language implied that investor protection is the sole responsibility of the auditor and could give investors false confidence that they can solely rely on an auditor's report as investment advice, when in fact there are many other factors investors should consider. Another commenter asserted that the proposed language could create a misimpression that auditors are permitted and expected to deviate from auditing standards when they believe such a departure would be warranted to further investors' interests. These commenters suggested that the Board clarify the introduction language in the final standard. Some commenters provided alternative language for the Board's consideration. For example, two commenters suggested replacing the phrase "properly conducted" in the last sentence of paragraph .01 with "conducted in accordance with the standards of the PCAOB" to align with language used in the auditor's report. One commenter suggested deleting paragraph .01 entirely.

After considering the comments received, the Board retained the proposed approach to the introduction section, while making certain revisions in light of the comments received.

The Board revised the first sentence of the introduction to state that the auditor has a fundamental obligation to protect investors through the preparation and issuance of informative, accurate, and independent auditor's reports. The Board also removed a redundant statement from proposed paragraph .01 ("and that obligation governs the auditor's work under the standards of the PCAOB"). This statement is unnecessary because paragraph .02 already clarifies that AS 1000 describes the general principles and

²⁰ See A Firm's System of Quality Control and Other Amendments to PCAOB Standard, Rules, and Forms, PCAOB Rel. No. 2024-005 (May 13, 2024).

²¹ *United States v. Arthur Young & Co.*, 465 U.S. 805, 817-18 (1984).

²² *Id.* at 817 (emphasis in original).

responsibilities of the auditor in properly conducting an audit in accordance with the standards of the PCAOB. This includes the fundamental obligation to protect investors as described in paragraph .01.

The fundamental obligation to protect investors is interwoven in the general principles and responsibilities that guide auditors throughout their work. Under current law, the auditor plays a critical role in the financial reporting process. By issuing opinions concerning whether financial statements are presented fairly, in all material respects, in conformity with the applicable financial reporting framework, auditors serve a special “public watchdog” function under the existing federal securities laws, requiring “complete fidelity to the public trust.”²³ As “gatekeepers,” auditors have a public responsibility to serve the public interest.²⁴ Investors rely on auditors to promote companies’ adherence to federal securities law mandates and companies’ disclosure of accurate and reliable financial information.²⁵ “Investor confidence is bolstered by the knowledge that public financial statements have been subjected to the rigors of independent and objective investigation and analysis” by an auditor.²⁶ This enhanced confidence of investors and other financial statement users in the company’s financial statements and ICFR also plays an integral role in maintaining the public trust in the capital markets. The introduction in the final standard underscores the auditor’s obligation under the Board’s auditing standards and other applicable laws and regulations.

The Board emphasized—in response to commenters who expressed concern that the introductory language, and specifically its use of the term “obligation,” could be interpreted to establish a new legal duty—that the introductory language does not alter any existing regulatory or legal requirements or obligations between auditors and investors. It does not establish a novel duty or new form of legal obligation. Rather, it reaffirms the auditor’s

obligation under the existing legal framework and the important role of the auditing profession in the capital markets.²⁷

Paragraph .01 of the final standard has also been revised, as suggested by some commenters, to state that the auditor’s responsibility²⁸ transcends the auditor’s relationship with management and the audit committee of the company under audit, providing the foundation for an objective and independent audit. This statement expresses a longstanding principle of public accounting.²⁹ Paragraph .01 also states that a properly conducted audit and the related auditor’s report enhance the confidence of investors and other financial statement users in the company’s financial statements and, if applicable, ICFR. The Board retained the phrase “properly conducted audit” to align with the description in paragraph .02. The Board removed the sentence that states that “An audit primarily benefits investors, who rely on the audit to provide an objective and independent opinion on whether the company’s financial statements are presented fairly and, if applicable, on the effectiveness of the company’s internal control over financial reporting” because it is redundant and unnecessary in the context of the surrounding statements. The Board does not believe that the language in paragraph .01 suggests that auditors may deviate from PCAOB auditing standards to protect investors. In fact, the language clearly establishes the fundamental duty of auditors to prepare and issue their reports in accordance with PCAOB standards. Similarly, the Board does not interpret

the language of paragraph .01 as suggesting that investors should view auditor’s reports as the sole source of investment advice. Collectively, these provisions emphasize that auditors play a critical role in ensuring the accuracy and transparency of a company’s financial information, and that this role helps investors make well-informed decisions and supports trust in a company’s financial statements.

Finally, a new footnote to paragraph .01 clarifies that references to “investors and other financial statement users” in AS 1000 encompass a broad spectrum of stakeholders. This group includes not only a company’s existing and potential shareholders, but also bondholders, lenders, other creditors, and others who use the company’s financial statements.³⁰

In addition to the revisions to paragraph .01, the Board relocated certain content, discussed in more detail below, from proposed paragraph .15 into a new note to paragraph .01. The note reminds auditors that their obligation to protect investors provides important context to the auditor’s work when applying the requirements of AS 1000 and other PCAOB standards and rules (e.g., when conducting interim reviews in accordance with AS 4105, *Reviews of Interim Financial Information*, or when conducting audits of ICFR in accordance with AS 2201).

Paragraph .02 summarizes the scope and content of AS 1000. The Board did not receive comment on this paragraph and adopted it as proposed.

2. Objectives of the Auditor

See Paragraph .03 of the New Standard

The proposed standard set forth three objectives of the auditor (a) in an audit of financial statements, to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and to issue an auditor’s report that expresses an opinion about whether the financial statements, taken as a whole, are presented fairly, in all material respects, in conformity with the applicable financial reporting framework; (b) in an audit of internal control over financial reporting, to obtain reasonable assurance about whether material weaknesses exist as of

²⁷ See Section 101(c)(6) of Sarbanes-Oxley (authorizing PCAOB to enforce compliance with the “Act, the rules of the Board, professional standards, and the securities laws relating to the preparation and issuance of audit reports and the obligations and liabilities of accountants with respect thereto, by registered public accounting firms and associated persons thereof . . .”) (emphasis added).

²⁸ The terms “obligation” and “responsibility” are used synonymously in this standard.

²⁹ See *Arthur Young*, 465 U.S. at 817–818 (“By certifying the public reports that collectively depict a corporation’s financial status, the independent auditor assumes a public responsibility transcending any employment relationship with the client. The independent public accountant performing this special function owes ultimate allegiance to the corporation’s creditors and stockholders, as well as to the investing public.”) (emphasis in original); AICPA Professional Standards, Vol. 2, Code of Professional Conduct, ET Section 53, Article II—The Public Interest (2002) (“...01 A distinguishing mark of a profession is acceptance of its responsibility to the public. The accounting profession’s public consists of clients, credit grantors, governments, employers, investors, the business and financial community, and others who rely on the objectivity and integrity of certified public accountants to maintain the orderly functioning of commerce.”).

²³ *Arthur Young*, 465 U.S. at 817–18.

²⁴ In *The Matter of KPMG Peat Marwick LLP*, SEC Rel. No. 34–43862, at 14 & n.54 (Jan. 19, 2001); see John C. Coffee Jr., *Gatekeepers: The Professions and Corporate Governance* 2–3 (2006) (describing “gatekeepers” as “repeat players who provide certification or verification services to investors, vouching for someone else who has a greater incentive than they to deceive”).

²⁵ In *The Matter of the Application of SW Hatfield, C.P.A.*, SEC Rel. No. 34–69930, at 33 (July 3, 2013) (reviewing PCAOB disciplinary action).

²⁶ *McCurdy v. SEC*, 396 F.3d 1258, 1261 (D.C. Cir. 2005); see *Arthur Young*, 465 U.S. at 819 n.15.

³⁰ See FASB, Statement of Financial Accounting Concepts No. 8, *Conceptual Framework for Financial Reporting*, Chapter 1, *The Objective of General Purpose Financial Reporting* (Dec. 2021) (“The objective of general purpose financial reporting is to provide financial information about the reporting entity that is useful to existing and potential investors, lenders, and other creditors in making decisions about providing resources to the entity”).

the date specified in management's assessment, and to issue an auditor's report that expresses an opinion on the effectiveness of the company's internal control over financial reporting; and (c) to communicate externally, as required by applicable professional and legal requirements. Other than AS 1001,³¹ the existing foundational standards do not include an objective.

The proposal defined the term "applicable professional and legal requirements" by referring to the term's definition in proposed QC 1000.³² That proposed definition included (i) professional standards, as defined in PCAOB Rule 1001(p)(vi); (ii) rules of the PCAOB that are not professional standards; and (iii) to the extent related to the obligations and responsibilities of accountants or auditors or to the conduct of engagements, rules of the SEC, other provisions of U.S. federal securities law, and other applicable statutory, regulatory, and other legal requirements.

Several commenters expressly supported the proposed objectives of the auditor. Some commenters suggested ways to further clarify these objectives. For example, one commenter suggested that the objectives be reframed as objectives of the "audit" rather than of the "auditor." Another commenter suggested moving the requirements on the determination of critical audit matters ("CAMs") from AS 3101.11, to the objectives of the auditor in AS 1000 in order to highlight the importance of CAMs. One commenter recommended that the objective related to the audit of ICFR refer to the relevant criteria used (e.g., criteria issued by the Committee of Sponsoring Organizations of the Treadway Commission) and clarify that it is integrated with the audit of financial statements.

With respect to the communication objective, one commenter stated that the proposed objective should also refer to communications with the company. Another commenter stated that the term "applicable legal and professional requirements" is overly broad and may inadvertently scope in legal requirements outside of public accountancy laws. An additional commenter suggested that AS 1000 refer instead to "PCAOB rules and standards."

The Board adopted the objectives in the final standard substantially as proposed, with the modifications discussed below.

The purpose of the objectives is to provide additional context for understanding the requirements in the standard. Therefore, the Board added the objective to "satisfy and fulfill the other general principles and responsibilities described in this standard." This provides more explicit linkage to the general principles and responsibilities set forth in the final standard.

The objectives refer, as proposed, to the "objectives of the auditor." Because the standard addresses the general principles and responsibilities of the auditor in conducting an audit, the Board believes that the objectives should be directed at the "auditor" rather than the audit as a whole.

The determination of CAMs is an important part of the auditor's reporting responsibilities and is encompassed under the applicable professional and legal requirements. The auditor's responsibilities for determining and communicating CAMs are described in AS 3101 and align with the stated objectives of that standard.³³ Rather than repeating these requirements, the Board instead added a note to paragraph .17 of the final standard that refers to the potential inclusion of CAMs in the auditor's report.

The suggested references to the relevant criteria used in the audit of ICFR are not suitable for the objective section of AS 1000 and are already covered in other PCAOB standards. The specific requirements relevant to performing an audit of ICFR are addressed in AS 2201, which provides the appropriate context for the framework to be used by the auditor when conducting an ICFR audit and integrating the audit of ICFR with an audit of financial statements.

As was proposed, the final standard includes an objective to communicate externally in accordance with applicable legal and professional requirements. The auditor has a responsibility to make certain communications (e.g., communications about audit results to the audit committee under AS 1301, *Communications with Audit Committees*), in addition to reporting externally on the results of the audit. The reference to these requirements in the objective is not intended to limit or preclude appropriate communications with company personnel. For example, PCAOB auditing standards require the auditor to conduct various inquiries of management and other company personnel (e.g., AS 2110, *Identifying and Assessing Risks of Material*

Misstatement, and AS 2201), which is part of complying with applicable professional and legal requirements.

For ease of reference, the final standard includes the definition of the term "applicable professional and legal requirements" as:

- Professional standards, as defined in PCAOB Rule 1001(p)(vi);
- Rules of the PCAOB that are not professional standards; and
- To the extent related to the obligations and responsibilities of accountants or auditors in the conduct of engagements or in relation to the quality control system, rules of the SEC, other provisions of U.S. federal securities law, ethics laws and regulations, and other applicable statutory, regulatory, and other legal requirements.

This definition is intended to capture all professional and legal requirements specifically related to engagements under PCAOB standards of issuers and SEC-registered broker-dealers, including relevant accounting, auditing, and attestation standards, PCAOB rules, SEC rules and regulations, other provisions of federal securities law, other relevant laws and regulations (e.g., state law and rules governing accountants), applicable ethics law and rules, and other legal requirements related to the obligations and responsibilities of accountants or auditors in the conduct of the firm's engagements or in relation to the quality control system.³⁴ It does not encompass requirements that apply to businesses generally, such as tax laws, safety regulations, and employment law.

This definition reflects revisions made in response to comments received on proposed QC 1000.³⁵ The definition

³⁴ The requirements related to compliance with applicable professional and legal requirements are meant to make clear that, in engagements subject to PCAOB auditing standards, all applicable professional and legal requirements must be followed. The requirement does not suggest that application of "other applicable statutory, regulatory, and other legal requirements" could supersede rules of the SEC, other provisions of U.S. federal securities law, rules of the PCAOB that are not professional standards, or PCAOB professional standards. On the contrary, requirements relating to "applicable professional and legal requirements" are meant to highlight the importance of adhering to other requirements when those requirements do not conflict with or abridge requirements of federal securities laws, PCAOB rules, or PCAOB standards.

³⁵ Two commenters supported the definition as proposed. One commenter recommended including the profession's ethical standards explicitly. Two commenters stated the phrase "other applicable statutory, regulatory, and other legal requirements" could be read broadly and extend beyond regulations that directly bear on the conduct of audit engagements. Another commenter suggested amending the definition of "professional standards" in PCAOB Rule 1001(p)(vi) to refer to "quality control standards" rather than "quality control policy and procedures."

³¹ See AS 1001.01.

³² See A Firm's System of Quality Control and Other Proposed Amendments to PCAOB Standards, Rules, and Forms, PCAOB Rel. No. 2022-006 (Nov. 18, 2022).

³³ See AS 3101.04 and .11-.17.

was expanded to explicitly mention ethics laws and regulations.³⁶ It was also refined to make clear that it encompasses statutory, regulatory, and other legal requirements beyond professional standards and other PCAOB rules “[t]o the extent related to the obligations and responsibilities of accountants or auditors in the conduct of engagements or in relation to the quality control system.” This change is designed to limit the breadth of the definition to the relevant circumstances. The phrase “quality control policies and procedures,” used in PCAOB Rule 1001(p)(vi), is drawn from Section 110(5) of Sarbanes-Oxley, and therefore no amendment to the PCAOB rule was necessary.

3. Professional Qualifications of the Auditor

i. Independence

See Paragraphs .04 Through .05 of the New Standard

The Board proposed to carry forward the existing requirement in AS 1005 for the auditor to be independent, and to align the language that describes auditor independence obligations with language used in PCAOB Rule 3520, *Auditor Independence*, and SEC Rule 2–01.³⁷ Specifically, the Board proposed to require the auditor to be independent of its audit client both in fact and in appearance throughout the audit and professional engagement period.³⁸ The proposed standard also clarified that the auditor is not independent with respect to an audit client if the auditor is not, or a reasonable investor with knowledge of all relevant facts and circumstances would conclude that the auditor is not, capable of exercising objective and impartial judgment on all matters encompassed within the engagement. This clarification aligned the standard with language used in SEC Rule 2–01(b)³⁹ to explain further the meaning of being independent both in fact and in appearance. In addition, the Board proposed to require the auditor to satisfy the independence criteria set out

in the rules and standards of the PCAOB, and satisfy all other independence criteria applicable to the engagement, including the independence criteria set out in the rules and regulations of the SEC under the federal securities laws.

Several commenters expressed support for including in AS 1000 the existing requirements from AS 1005 and stating more directly the auditor’s obligation to comply with the independence requirements of the PCAOB and SEC. Two commenters, including an investor-related group, suggested that the Board replace references to “audit client” with “company under audit.” One commenter asserted that using “client” does not recognize that the auditor’s public responsibility transcends the employment relationship with the client. Another commenter asserted that the use of “client” mischaracterizes the relationship between auditor and the company or its management, and places the auditor in a “subservient” position. In addition, one commenter suggested adding to the final standard additional language from SEC Rule 2–01(b) to indicate that the PCAOB and SEC will consider “all relevant facts and circumstances” in determining independence. That commenter also suggested limiting the use of the term “independent” in the title of the auditor’s report to only those auditors that have complied with the SEC and PCAOB rules.

After considering the comments received, the Board adopted the requirements related to independence substantially as proposed with some modifications. The Board agrees with the commenters’ observation that language used in the Board’s standards can help emphasize that audits are performed primarily for the benefit of investors, not management of the company. Accordingly, the Board replaced references to “audit client” with “company under audit” and added a footnote to clarify that the phrase “company under audit” has the same meaning as “audit client” as defined by PCAOB Rule 3501(a)(iv).

The Board did not add to the final standard additional language from SEC Rule 2–01(b) stating that the PCAOB and SEC will consider “all relevant facts and circumstances” in determining independence. The Board’s standards do not address the SEC’s processes, and need not repeat in this standard that relevant matters are considered in PCAOB independence determinations.⁴⁰

The Board also did not add limitations on the use of the term “independent” in the title of the auditor’s report. AS 3101 contains requirements regarding the content of the auditor’s report, including the title “Report of Independent Registered Public Accounting Firm.” AS 3101 also requires that the auditor’s report include a statement that the auditor is required to be independent with respect to the company in accordance with U.S. federal securities laws and the applicable rules and regulations of the SEC and PCAOB. Imposing any limitations on the use of the term “independent” in the title, as suggested by a commenter, is outside of the scope of this standard.

ii. Ethics

See Paragraph .06 of the New Standard

The Board proposed to require the auditor to comply with applicable ethics requirements, including the rules and standards of the PCAOB. Under the proposed standard, ethics requirements included the rules in Section 3, Part 5 of PCAOB rules and proposed EI 1000, *Integrity and Objectivity*, of the QC proposal. The existing foundational standards do not reference the auditor’s responsibility to comply with ethics requirements.

A few commenters suggested revisions to the proposed requirement. Two commenters, including an investor-related group, stated that the proposed requirement is weak because it focused on merely complying with rules and standards of the Board. The investor-related group also suggested adding language that discusses subordination of judgment to others, specifically those outside the audit firm (e.g., external specialists). The other commenter recommended requiring that firms create and maintain codes of ethics embracing the principles of proposed EI 1000 and upholding the integrity of capital markets and auditors’ fundamental obligations to investors. An additional commenter suggested addressing in the standard broader ethical principles, such as integrity and objectivity, in addition to compliance with rules and standards.

After considering the comments received, the Board retained the requirement to comply with ethics

Services Related to Internal Control Over Financial Reporting (“Independence requirements provide that an auditor is not independent of his or her audit client if the auditor is not, or a reasonable investor with knowledge of all relevant facts and circumstances would conclude that the auditor is not, capable of exercising objective and impartial judgment on all issues encompassed within the accountant’s engagement.”) (emphasis added).

³⁶ These include those arising under state law or the law of other jurisdictions (e.g., obligations regarding client confidentiality).

³⁷ 17 CFR 210.2–01 (Regulation S–X Rule 2–01).

³⁸ See PCAOB Rule 3501, *Definitions of Terms Employed in Section 3, Part 5 of the Rules*, for the definition of the term “audit and professional engagement period.”

³⁹ Under the general standard in SEC Rule 2–01(b), the SEC “will not recognize an accountant as independent, with respect to an audit client, if the accountant is not, or a reasonable investor with knowledge of all relevant facts and circumstances would conclude that the accountant is not, capable of exercising objective and impartial judgment on all issues encompassed within the accountant’s engagement.”

⁴⁰ See Note to paragraph (b) of PCAOB Rule 3525, *Audit Committee Pre-approval of Non-audit*

requirements substantially as proposed, with the modifications discussed below. The Board added the word “ethics” before “rules and standards of the PCAOB” to provide a clearer indication of the rules and standards referenced. Under the final standard, applicable ethics requirements are not limited to the ethics rules and standards of the PCAOB but also include state law and the laws of other jurisdictions that may establish additional ethics provisions with which the auditor is required to comply (e.g., obligations regarding conflicts of interest).

The Board agrees with the underlying point of the comment that auditors should not subordinate their judgment to individuals outside the audit firm (e.g., external specialists) and believe that the new standard will achieve the desired objective of the comment. A subordination or relinquishment of professional judgment would be inconsistent with the requirements of AS 1000.09–.10 related to due professional care, which are discussed below. In addition, EI 1000 addresses the broader ethical principles of integrity and objectivity. Specifically, the overarching requirements in EI 1000 include (i) maintaining integrity, which includes being honest and candid, not knowingly or recklessly misrepresenting facts, and not subordinating judgment; and (ii) maintaining objectivity, which includes being impartial, intellectually honest, and free of conflicts of interest. The intent of the requirement to comply with ethics in AS 1000 is to remind auditors of their responsibilities described in EI 1000 and Section 3, Part 5 of PCAOB rules. Therefore, additional discussion of broader ethical principles and responsibilities is appropriately addressed in EI 1000 and need not be duplicated in AS 1000. The Board expanded the reference to EI 1000 in footnote 6 of paragraph .06 of AS 1000 to clarify that EI 1000 specifically requires auditors to maintain integrity and objectivity. Further clarification on matters related to subordination of professional judgment is unnecessary in this release. Lastly, the Board considered comments related to firms’ adoption of an ethics code as part of the adoption of EI 1000.

iii. Competence

See Paragraphs .07 and .08 of the New Standard

a. Description of Competence

The Board proposed to require that the audit be performed by an auditor who has competence to conduct an audit in accordance with applicable professional and legal requirements.

Competence, as described in the proposed standard, consists of having the knowledge, skill, and ability that enable an auditor to perform the assigned activities in accordance with applicable professional and legal requirements and the firm’s policies and procedures. In the proposing release, the Board explained that the auditor’s knowledge and skill relate to adequate technical training and proficiency as an auditor, and the auditor’s ability relates to the capabilities to perform, and in the case of supervisory staff, to review assigned tasks. The proposed standard also provided that, in determining the appropriate level of competence, the measure is qualitative rather than quantitative because quantitative measurement may not accurately reflect the experience gained over time. A note to the proposed requirement stated that competence includes knowledge and expertise in accounting and auditing standards and in SEC rules and regulations relevant to the company being audited and to the related industry or industries in which it operates. The proposed requirement was consistent with the auditor’s existing responsibilities under AS 1010 for maintaining “adequate technical training and proficiency” but used updated terminology.

Several commenters sought greater clarity in the proposed requirement, stating that it did not account for the collective competence of the engagement team or that it might imply that all individual members of an engagement team are expected to have the same level of competence. These commenters generally suggested (i) revising the requirement to apply to, for example, “the engagement team, including specialists” or “auditors, collectively” instead of “an auditor” and (ii) clarifying that necessary competence is commensurate with the assigned tasks of the individual auditor. One commenter suggested (i) defining the individuals intended to be covered by the requirement, including subject matter experts and EQRs; (ii) explaining that the competence of individuals varies based on a variety of factors; and (iii) including quantitative factors in the measure of competence. Another commenter noted that the proposed requirement could be interpreted to limit the ability to assign challenging work to junior staff because they may lack significant experience.

Some commenters, mostly firms and professional organizations, also expressed concern with the description of competence in the note to the proposed requirement—which referred to having “expertise” in SEC rules and

regulations and the relevant industry of the company being audited—and asked for additional clarification. These commenters asserted that the term “expertise” may impose a higher standard of competence than intended and could imply that the expected level of knowledge is that of a person qualified to engage in the practice of another profession or occupation (e.g., the legal profession). One of these commenters also expressed concern with the implication that a partner without relevant expertise in the industry in which the issuer operates may not be competent to perform an audit of the issuer, even with the assistance of other firm or engagement team members with relevant industry expertise. Several commenters recommended deleting the reference to “expertise” or using alternative language such as “proficiency” or “sufficient knowledge.”

After considering the comments received, the Board adopted the requirement related to competence substantially as proposed, with the modifications discussed below.

First, consistent with the Board’s description in the proposal, the Board continues to believe the level of competence needed to conduct the audit is driven by the activities assigned to the individual auditors performing those activities. As the assigned activities in an audit vary from individual to individual, so does the required level of competence to complete those activities in accordance with applicable professional and legal requirements and the firm’s policies and procedures. For example, a first-year auditor is not expected to have the same level of competence as a more experienced auditor because the tasks assigned to the seasoned auditor generally require experience gained over time. Further, PCAOB standards and rules use the term “auditor” to mean both a firm registered with the PCAOB and its associated persons.⁴¹ Therefore, the Board believes that defining the individuals covered by the requirement or revising terminology to “auditors” or “engagement team,” as suggested by some commenters, is not necessary. The requirements regarding the appropriate assignment of responsibilities to engagement team members and proper supervision are addressed in other PCAOB standards.⁴²

Second, the Board agrees that quantitative measures are not wholly

⁴¹ See PCAOB Rule 1001(a)(xiii).

⁴² See, e.g., paragraph .05 of AS 2301, The Auditor’s Responses to the Risks of Material Misstatement, and AS 1201.05.

irrelevant when measuring competence. Quantitative measures alone may not accurately reflect the nature of experience gained over time and therefore competence should not be measured exclusively on a quantitative basis.⁴³ In consideration of comments, the final requirement clarifies that competence is measured both qualitatively and quantitatively.

Third, the intent of the proposed requirement's note (providing that competence "includes knowledge and expertise" in certain areas) was to provide additional direction to auditors on the meaning of competence in the context of the company being audited. The Board did not intend to impose a higher standard of competence beyond having the knowledge, skill, and ability to enable the auditor to perform the assigned activities in accordance with applicable professional and legal requirements. The Board therefore changed "expertise" to "proficiency" in the final requirement in response to comments. Nevertheless, the Board continues to believe that understanding the company's business and being proficient in the rules and regulations relevant to the company under audit and its related industry is an important part of competence. For example, an engagement partner with significant experience mostly in auditing manufacturing companies may not necessarily have the appropriate level of competence to oversee, and have primary responsibility for, an audit of a financial institution.

b. Developing and Maintaining Competence

The Board also proposed to require that the auditor develop and maintain competence through an appropriate combination of academic education; professional experience in accounting and auditing with proper supervision; and training, including accounting, auditing, independence, ethics, and other relevant continuing professional education. Existing AS 1010 includes a similar requirement.

Investor-related groups advocated for the inclusion of investor-related training that focuses on investors as the primary beneficiaries of the audit and being responsive to investors' needs. These commenters also emphasized the importance of including the auditor's understanding of the business and industry related to the company under audit as part of developing competence. One investor-related group suggested specific training on materiality.

The Board retained the requirement to develop and maintain competence as proposed. The Board agrees with investor-related groups' views on the importance of protecting investors when conducting an audit. In that regard, paragraph .01 of the final standard and the Board's related discussion provide the context of investor protection that is relevant to the auditor's compliance with the requirements for developing and maintaining competence. Further, in considering commenters' suggestion about investor-focused training, the Board believes that the implementation of the final standard will necessarily involve training auditors on the application of the relevant requirements, including conducting an audit with investor protection in mind.

The note to paragraph .07 of the final standard reinforces the need for auditors to have knowledge and proficiency in the requirements relevant to the company being audited and the related industry. Further, the auditor's responsibilities for understanding the company's business and consideration of materiality in planning and performing an audit are specifically addressed in other PCAOB auditing standards,⁴⁴ and the Board expects that these responsibilities would already be included in training on auditing standards.

4. Due Professional Care, Including Professional Skepticism

i. Due Professional Care

See Paragraphs .09 Through .10 of the New Standard

The Board proposed to require the auditor to exercise due professional care in all matters related to the audit. The proposed standard stated that due professional care (i) concerns what the auditor does and how well the auditor does it, and (ii) means acting with reasonable care and diligence, exercising professional skepticism, acting with integrity, and complying with applicable professional and legal requirements. The proposed requirement was based on the existing requirement in AS 1015 to exercise due professional care.

The proposing release explained that exercising due professional care "in all matters related to the audit" would encompass all aspects of planning and performing an audit, including client acceptance and continuance procedures, and would extend to periods after the issuance of the auditor's report, such as

completion of audit documentation,⁴⁵ reporting on Form AP, *Auditor Reporting of Certain Audit Participants*,⁴⁶ and procedures performed in connection with filings under the federal securities statutes.⁴⁷ The Board also proposed to retain language from existing standards related to an auditor's use of the work of other auditors, which emphasized that other auditors are responsible for performing their work with due professional care.⁴⁸

Some commenters acknowledged that due professional care is an important principle that should be retained in the final standard. Several commenters expressed support for requiring auditors to exercise due professional care "in all matters related to the audit."

Some commenters, primarily some firms, advocated for retaining certain contextual language from AS 1015.03–.04, including, for example, the description of due professional care in the 1932 legal treatise, *Cooley on Torts*.⁴⁹ These commenters expressed concern that without such language there may be a lack of transparency, or confusion among investors and other stakeholders, about the limitations of due professional care.

After considering comments, the Board adopted the requirement to exercise due professional care as proposed. The Board continues to believe that the description of due professional care in the final standard is consistent with the description in AS 1015.03 (and the reference in the current standard to the legal treatise, *Cooley on Torts*), which uses the terms "reasonable care and diligence" and "good faith and integrity but not infallibility" to describe due care. As discussed in the proposal, the Board retained explicit reference to "reasonable care and diligence," which the Board believes is well understood. The Board also believes that "good faith

⁴⁵ See AS 1215.15 (as proposed to be amended).

⁴⁶ See PCAOB Rule 3211, Auditor Reporting of Certain Audit Participants.

⁴⁷ See AS 4101, *Responsibilities Regarding Filings Under Federal Securities Statutes*, which describes the auditor's responsibilities when the auditor's report is included in filings under federal securities statutes.

⁴⁸ See Planning and Supervision of Audits Involving Other Auditors and Dividing Responsibility for the Audit with Another Accounting Firm, PCAOB Rel. No. 2022–002 (June 21, 2022) (amendments approved by the SEC in Rel. No. 34–95488 (Aug. 12, 2022)), which amended AS 1015 to add this provision.

⁴⁹ The treatise states, among other things, that "no man, whether skilled or unskilled, undertakes that the task he assumes shall be performed successfully, and without fault or error; he undertakes for good faith and integrity, but not for infallibility, and he is liable to his employer for negligence, bad faith, or dishonesty, but not for losses consequent upon pure errors of judgment."

⁴³ The description of competence is consistent with the description in QC 1000.

⁴⁴ See AS 2110 and AS 2105, Consideration of Materiality in Planning and Performing an Audit.

and integrity” means acting with “integrity.” The Board’s use of the term “integrity” aligns with its meaning established in EI 1000, which the Board adopted in connection with the Quality Control rulemaking. EI 1000 codifies the concepts of integrity and objectivity, emphasizing that integrity includes being honest and candid, not knowingly or recklessly misrepresenting facts, and not subordinating judgment.⁵⁰ The Board believes that the terms used to describe due professional care are clear and should not cause confusion, as suggested by some commenters, because the Board did not change the meaning of due professional care.

The proposed standard specified that, for engagement partners, due professional care also includes (i) appropriately assigning responsibilities to, and supervising, engagement team members; (ii) determining that the audit is properly planned and performed to obtain reasonable assurance; (iii) evaluating that significant findings or issues are appropriately addressed; (iv) determining that significant judgments and conclusions on which the auditor’s report is based are appropriate and supported by sufficient appropriate audit evidence; and (v) determining that required communications under applicable professional and legal requirements have been made.

The proposed clarifications of the engagement partner’s responsibilities leveraged existing requirements for planning and performing an audit and for completing the corresponding audit documentation. For example, AS 1215 describes matters that are considered to be significant findings or issues in an audit and requires the auditor to document the significant findings or issues, including the actions taken to address them.⁵¹ As part of the engagement partner’s supervisory responsibilities under AS 1201, the proposal stated that the engagement partner would need to evaluate (in a timely manner) the significant findings and issues identified by the engagement team to ensure appropriate action was taken.⁵²

Similarly, the proposal stated that significant judgments made by the engagement team, which AS 1220 specifically requires the EQR to review, also warrant the engagement partner’s review. Because the engagement partner has primary responsibility for the engagement, they have primary responsibility for the significant judgments made during the engagement,

notwithstanding any involvement in or responsibility for those judgments by firm personnel outside of the engagement team, such as members of the firm’s national office. Accordingly, the “significant judgments made by the engagement team” include all of the significant judgments made during the engagement.⁵³ The proposed standard aligned the engagement partner’s supervisory and review activities with existing auditor responsibilities.

A few commenters addressed the proposed requirement regarding the engagement partner’s responsibilities for exercising due professional care. One commenter recommended separating the partner’s responsibilities from the broader requirement to exercise due professional care. Another commenter expressed concern that, as presented, the responsibilities of the engagement partner could be viewed as a substitute for the broader responsibilities applicable to all auditors. This commenter suggested emphasizing in the final standard that for engagement partners, the responsibilities are in addition to those required for all auditors.

Several commenters also suggested clarifications to the proposed requirements. For example, one commenter suggested that the requirements be extended to team members performing supervisory activities. Another commenter pointed to potential inconsistencies with requirements of AS 1201 and AS 2101, noting that AS 1201 does not explicitly require the partner to assign activities to team members that adequately match their levels of competence and allows the partner to seek assistance from appropriate engagement team members in fulfilling responsibilities. One commenter recommended adding a footnote to AS 1220 to the discussion of significant judgments and conclusions.

In response to commenters, the Board relocated the proposed engagement partner’s responsibility for due professional care into a separate paragraph in the final standard, with certain clarifications. Specifically, the Board agrees with commenters’ views that the engagement partner is not required to directly assign responsibilities to all engagement team members (e.g., audit staff at other accounting firms involved in the audit). Nevertheless, consistent with AS 1015.06, the engagement partner is responsible for the appropriate

assignment of tasks to, and supervision of, engagement team members. As such, the final standard states that the engagement partner’s responsibility for due professional care includes “being responsible for the appropriate assignment of responsibilities to, and supervision of, engagement team members.” This formulation acknowledges that in certain audit engagements, such as large, multi-tiered audits, the engagement partner may not be directly assigning work to engagement team members. Instead, other engagement team members performing supervisory activities may assist the engagement partner and inform engagement team members of their responsibilities.⁵⁴

The Board believes that relocating the engagement partner’s responsibility for due professional care into a separate paragraph helps draw a distinction between the responsibilities applicable to all auditors and those that are incremental for engagement partners. To clarify this further, the Board added “also” to the requirement in paragraph .10 to indicate that the engagement partner responsibilities for due professional care are in addition to those applicable to all auditors. The Board did not expand the applicability of the engagement partner responsibilities described in AS 1000 to other members of the engagement team performing supervisory activities because, as discussed above, the intent of this requirement is to focus the engagement partner on exercising due professional care as the person with the primary responsibility for the engagement and its performance. As suggested by one commenter, the Board added a footnote to the final standard referencing AS 1220 for the discussion of significant judgments and conclusions. The Board adopted the remaining provisions of the requirement as proposed.

ii. Description of Professional Skepticism

See Paragraph .11 of the New Standard

The proposed standard stated that exercising due professional care includes exercising professional skepticism in conducting an audit, and described professional skepticism as an attitude that includes a questioning mind and a critical assessment of information related to the audit. This requirement is based on the existing auditor responsibility to exercise professional skepticism in AS 1015. The Board emphasized in the proposal that

⁵⁰ See also PCAOB Rel. No. 2024–005.

⁵¹ See AS 1215.12.

⁵² See AS 1201.05.

⁵³ See Auditing Standard No. 7—Engagement Quality Review and Conforming Amendment to the Board’s Interim Quality Controls Standards, PCAOB Rel. No. 2009–004 (July 28, 2009), at 4 n.7.

⁵⁴ See AS 1201.05.

application of professional skepticism extends beyond the information used as audit evidence, which is described in AS 1105.02 as the information “that is used by the auditor in arriving at conclusions on which the auditor’s opinion is based.” For example, by exercising professional skepticism in the preparation of Form AP, the auditor may become aware of inconsistencies in total audit hours reported by another accounting firm participating in the audit based on the level of work assigned to that accounting firm and take corrective action.

An investor-related group supported the proposed description of professional skepticism to include a critical assessment of information related to the audit. In contrast, a number of other commenters, mostly firms, expressed concern about the proposed change in the description of professional skepticism from a critical assessment of “audit evidence” to “information related to the audit,” stating that this language is overly broad and its meaning unclear. Some of these commenters noted that, unlike with audit evidence, there is no established framework for auditors to assess information related to the audit and it is unclear what such an assessment would entail. Many of these commenters advocated for retaining the extant description of professional skepticism in AS 1015.07, which includes “a critical assessment of audit evidence.”

Some commenters offered additional explanation or suggestions, for example:

- One commenter indicated they were unable to identify information, other than Form AP data, that would be considered “information related to the audit” that is not already part of “audit evidence.” This commenter and another recommended specifically incorporating Form AP data into the requirement.
- One commenter indicated the proposed language could risk including information related to the audit that was never presented to the auditor. This commenter suggested retaining reference to “audit evidence” and including a reference to information obtained to comply with rules of the Board.
- Another commenter recommended retaining the reference to “audit evidence” because this concept is supplemented by the requirements in proposed paragraph .11 and by the overarching responsibility to exercise due professional care in relation to all matters related to the audit (including the preparation of Form AP).

Several commenters offered other views related to the description of

professional skepticism. For example, one commenter stated that the difference between “critical assessment of information related to the audit” and “objective evaluation of evidence obtained in an audit” in proposed paragraph .11 is unclear. This commenter suggested combining proposed paragraphs .10 and .11 or providing further guidance, including guidance that is aligned with other standard setters. Another commenter questioned the assumption in the proposed standard that all auditors can exercise professional skepticism consistently for the duration of the audit, pointing to a lack of research.

After consideration of comments, the Board revised the description of professional skepticism. The final standard describes professional skepticism as “an attitude that includes a questioning mind and a critical assessment of audit evidence and other information that is obtained to comply with PCAOB standards and rules.” While the Board agrees with commenters that information related to the audit that is obtained by the auditor is generally audit evidence, the Board continues to believe that the exercise of professional skepticism in an audit extends beyond the evaluation of the sufficiency and appropriateness of audit evidence. Professional skepticism is an attitude held by the auditor throughout the audit process. For example, AS 2401, *Consideration of Fraud in a Financial Statement Audit*, provides that professional skepticism requires an ongoing questioning of whether the information and evidence obtained suggests that a material misstatement due to fraud has occurred.⁵⁵ The revised description in AS 1000 retains the extant reference to “critical assessment of audit evidence” but also, as suggested by one commenter, refers to information obtained by the auditor to comply with PCAOB standards and rules, such as information to complete Form AP. The Board believes that the revised description will provide auditors with a clear framework for exercising professional skepticism and aligns with the auditor’s obligation to exercise due professional care, which applies to all matters related to the audit.

As suggested by one commenter, the final standard also combines in paragraph .11 the description of professional skepticism (proposed paragraph .10) with the description of what exercising professional skepticism entails (proposed paragraph .11) discussed below. The Board believes this unified paragraph will provide

better context for the application of professional skepticism.

iii. Exercise of Professional Skepticism See Paragraph .11 of the New Standard

The proposed standard described several factors involved in the exercise of professional skepticism, which were largely consistent with extant requirements. Under the proposed standard, the auditor’s exercise of professional skepticism included:

- Objective evaluation of evidence obtained in an audit (including information that supports and corroborates management’s assertions regarding the financial statements or internal control over financial reporting and information that contradicts such assertions), and consideration of the sufficiency and appropriateness (*i.e.*, relevance and reliability) of that evidence;
- Remaining alert to conditions that may indicate possible misstatement due to error or fraud;
- Not relying on evidence that is less than persuasive;
- Not assuming that management is honest or dishonest; and
- Consideration of potential bias on the part of management and the auditor.

Some commenters provided views on specific aspects of the factors involved in the auditor’s exercise of professional skepticism. The comments and related responses are discussed in more detail below.

Objectively evaluating evidence. One commenter suggested requiring the auditor to search for contradictory evidence. Another commenter stated that the proposed description did not sufficiently address professional skepticism in obtaining audit evidence and instead focused only on evaluating the evidence. One commenter stated that the proposed description was unclear and suggested using more direct language, including requiring the auditor to be more neutral in the assessment (*e.g.*, evaluating evidence that both supports assertions and evidence that does not).

The intent of paragraph .11a of AS 1000 is not to alter the responsibilities for obtaining and evaluating evidence addressed in AS 1105, but to remind auditors of their responsibility to exercise professional skepticism in connection with both obtaining and evaluating audit evidence. As discussed in the proposal, sufficient appropriate audit evidence is necessary to support the auditor’s opinion. While primarily obtained from audit procedures performed during the audit, audit evidence may also include information

⁵⁵ See AS 2401.13.

obtained from other sources such as previous audits, and client acceptance or continuance procedures. The exercise of professional skepticism is particularly important in obtaining and evaluating audit evidence when responding to assessed risks of material misstatement, including fraud risks.

Audit evidence consists of both information that supports and corroborates management's assertions and information that contradicts such assertions.⁵⁶ The auditor's appropriate application of professional skepticism includes critically assessing this information and should result in procedures that are focused on obtaining evidence that is more relevant and reliable,⁵⁷ such as evidence obtained directly by the auditor and evidence obtained from independent, knowledgeable sources. Further, if audit evidence obtained from one source is inconsistent with audit evidence obtained from another, the auditor is required to perform the audit procedures necessary to resolve the matter and should determine the effect, if any, on other aspects of the audit.⁵⁸

Professional skepticism is important in all aspects of the audit, particularly in those areas of the audit that involve significant management judgments or transactions outside the normal course of business. It is ultimately the responsibility of each individual auditor to appropriately apply professional skepticism throughout the audit, including when (i) identifying and assessing risks of material misstatement, (ii) performing tests of controls and substantive procedures, and (iii) evaluating audit results. For example, a lack of professional skepticism in the risk assessment process could result in an auditor not identifying or assessing risks appropriately, which could impact the effectiveness of the audit.

Remaining alert to conditions that may indicate possible misstatement due to fraud. The Board did not receive significant comments in this area. As part of exercising professional skepticism, the auditor remains alert to conditions that may indicate possible misstatement due to error or fraud. This includes, for example, being alert to information that calls into question the reliability of documents and responses

to inquiries the auditor plans to use as audit evidence. Such information could identify conditions that may indicate possible fraud or error in the financial statements. As discussed above, AS 2401 provides further requirements regarding potential fraud risk factors.

Not relying on evidence that is less than persuasive. One commenter stated that the proposed phrase "not rely" appears to be more restrictive than the existing phrase "not be satisfied with" in AS 1015.09 because the proposed phrase would preclude the auditor from placing any reliance on anything less than completely persuasive evidence, even in combination with other persuasive evidence.

The proposed phrase "not rely" was intended to convey that, consistent with AS 1015.09, exercising professional skepticism involves seeking evidence that is more persuasive rather than settling on evidence that may be less so. AS 1000 is not intended to address the sufficiency and appropriateness of evidence. To avoid confusion, the final standard retains the existing terminology from AS 1015 as "not being satisfied with evidence that is less than persuasive." The requirements for obtaining audit evidence, including evaluating its relevance and reliability, are discussed in AS 1105, which provides that the quantity of audit evidence needed is affected by both the risk of material misstatement and the quality of the evidence obtained (*i.e.*, its relevance and reliability). To supplement evidence that is less relevant or obtained from a less reliable source, an auditor would need to gather additional evidence. The appropriate application of professional skepticism focuses the auditor on seeking the best evidence reasonably obtainable.

Not assuming that management is honest or dishonest. An investor-related group referenced certain views expressed in the 2000 report by the Public Oversight Board's Panel on Audit Effectiveness.⁵⁹ That report recommended that auditing standards require forensic-type fieldwork in which auditors would "modify the otherwise neutral concept of professional skepticism and presume the possibility of dishonesty at various levels of management, including collusion, override of internal control and falsification of documents."⁶⁰ The Board believes that establishing a presumption of management's dishonesty would have broader

implications beyond the exercise of professional skepticism under this standard.

Consideration of potential bias on the part of management and the auditor. Several commenters expressed concern that the obligations related to consideration of the auditor's own bias were unclear or could be viewed as a requirement to seek contradictory evidence. Some of these commenters noted that consideration of auditor bias is inherent in the requirements for evaluating audit evidence under AS 1105 and suggested deleting the reference to "and the auditor" from proposed paragraph .11e. One commenter suggested aligning this concept with the approach used by the AICPA in their revised audit evidence standard. Two commenters also questioned the nature and extent of documentation necessary to demonstrate consideration of auditor bias. One investor-related group advocated for requiring the auditor to affirmatively consider the risk of bias, particularly confirmation bias, arising out of the financial relationship between management and the auditor.

The Board continues to believe that it is important to include reference to auditor bias in connection with exercising professional skepticism because certain conditions inherent in the audit environment create incentives and pressures that could impede the appropriate application of professional skepticism and allow unconscious bias to influence decisions. Examples of these incentives and pressures include avoiding significant conflicts with management, providing an unqualified audit opinion prior to the company's filing deadline, achieving high client satisfaction ratings, keeping audit costs low, or cross-selling other services.

As discussed in the proposal, it is important for the auditor, as part of exercising professional skepticism, to consider the impact of management bias and the auditor's own bias that could affect the auditor's judgments. For example, the tendency to seek confirming information can lead the auditor to seek audit evidence that is only consistent with management's explanations, or to favor conclusions that are consistent with the auditor's initial beliefs or conclusions reached in prior year audits. In exercising professional skepticism, the auditor could mitigate such potential bias by being aware of "confirmation bias," considering alternatives provided by others, and being aware of contradictory

⁵⁶ See AS 1105.02. A new footnote has been added to AS 1000.11a, referring to AS 1105 for the discussion of management's assertions regarding the financial statements and internal control over financial reporting, and the proposed phrase "regarding the financial statements or internal control over financial reporting" has been deleted from paragraph .11a.

⁵⁷ See AS 1105.07--08.

⁵⁸ See AS 1105.29.

⁵⁹ See Public Oversight Board, The Panel on Audit Effectiveness Report and Recommendations (Aug. 31, 2000).

⁶⁰ *Id.* at 88-89.

information.⁶¹ Auditors and management may also have biases related to electronic information (e.g., a belief that electronic information is either always reliable or inherently prone to error). For example, a tendency to favor output generated from automated systems, even when contradictory information raises questions as to whether such output is reliable, illustrates a form of bias. Exercising professional skepticism, including critically assessing information related to the audit, helps the auditor address the effects of potential bias on professional judgment and decision-making. It is important to clarify, however, that the consideration of potential bias discussed above does not change the auditor's responsibilities for evaluating contradictory evidence, as suggested by some commenters.

Finally, the Board did not add new documentation requirements for demonstrating the auditor's exercise of professional skepticism beyond those addressed in AS 1215. Auditors can demonstrate that their work encompassed the exercise of professional skepticism by documenting the procedures performed and conclusions reached in accordance with AS 1215.

After consideration of the comments, the Board adopted the provisions for exercising professional skepticism substantially as proposed, with the modifications discussed above.

5. Professional Judgment

See Paragraph .12 of the New Standard

Auditors exercise professional judgment throughout the audit, and existing standards refer to the use of professional judgment, but do not describe in detail what professional judgment means. The proposed standard provided that the auditor must exercise professional judgment and included a description of professional judgment. As discussed in the proposing release, auditors exercise professional judgment throughout the audit. For example, the auditor exercises professional judgment in:

- Determining the areas to be tested and the nature, timing, and extent of the tests to be performed;
- Interpreting the results of audit testing and evaluating audit evidence;
- Evaluating the reasonableness of accounting estimates in significant accounts and disclosures, based on information that could reasonably be

expected to be available through the date of the auditor's report;⁶²

- Determining if there are any CAMs in the audit of the financial statements;⁶³ and

- Determining the nature and extent of documentation to comply with documentation requirements.⁶⁴

As proposed, professional judgment involved applying relevant training, knowledge, and experience to make informed decisions and reach well-reasoned conclusions about the courses of action that are appropriate in the circumstances such that the audit is planned and performed, and the report or reports are issued, in accordance with applicable professional and legal requirements.

Several commenters, primarily firms, expressed concern that the proposed description of professional judgment could be interpreted as imposing a new strict liability requirement. These commenters suggested removing the phrase "such that the audit is planned and performed, and the report or reports are issued, in accordance with applicable professional and legal requirements" in the description, noting that a deficiency in an auditor's compliance with applicable professional and legal requirements should not, by default, indicate a failure to exercise appropriate professional judgment. In the view of these commenters, this implication would be contrary to the established interpretation of an auditor's responsibilities, which recognizes that reasonable observers may disagree regarding whether applicable standards were complied with while agreeing that the matter in question was within the purview of the auditors' professional judgment and could result in hindsight challenges of auditors' judgments.

One commenter recommended that the description of professional judgment refer to "sound" judgment, consistent with the description used by the International Ethics Standards Board for Accountants ("IESBA").⁶⁵ Another commenter asked for clarification of the concept of "well-reasoned conclusions,"

⁶² See AS 2501, *Auditing Accounting Estimates, Including Fair Value Measurements*, which discusses the auditor's responsibility to obtain sufficient appropriate evidence to determine whether accounting estimates in significant accounts and disclosures are properly accounted for and disclosed in the financial statements.

⁶³ See AS 3101 for requirements regarding CAMs.

⁶⁴ See AS 1215 for documentation requirements.

⁶⁵ See IESBA, *Handbook of the International Code of Ethics for Professional Accountants* (2023), Subsection 113—Professional Competence and Due Care, at 113.1 A1 ("Serving clients and employing organizations with professional competence requires the exercise of sound judgment in applying professional knowledge and skill when undertaking professional activities.").

noting potential differences with the definition of professional judgment established by other standard setters. Two commenters advocated for the establishment of a judgment framework by the Board. One commenter stated that they heard auditors express the need for more clarity about the degree of documentation necessary to demonstrate their reasoned judgment. Another commenter suggested adding the concept of materiality to the description of an auditor's exercise of judgment, based on the description of judgment in AS 2815.04 with regard to the auditor's opinion on financial statements.

The proposed phrase "such that the audit is planned and performed, and the report or reports are issued, in accordance with applicable professional and legal requirements" was meant to provide context to the application of professional judgment and was not intended to introduce a strict liability requirement. After considering the comments received, the Board removed this phrase in the final description of professional judgment. The Board continues to believe that it is important to clarify that the use of professional judgment does not allow for an arbitrary exercise of discretion. While conclusions could vary, auditors are required to apply relevant training, knowledge, and experience to make informed decisions and reach well-reasoned conclusions about the courses of action that are appropriate in the circumstances. Therefore, the Board added a note to paragraph .12 to clarify that professional judgment is applied in the context of conducting an audit with due professional care in accordance with applicable professional and legal requirements. The Board believes that this note properly frames the exercise of professional judgment without implying that a deficiency in an auditor's compliance with applicable professional and legal requirements would by default also indicate a failure to exercise appropriate professional judgment.

The Board did not change the description of professional judgment to include "sound judgment" as the Board believes that term is redundant with the phrase "well-reasoned." The phrase "well-reasoned," used in the context of an auditor exercising professional judgment and reaching conclusions, is clear because it refers to judgment made and conclusions reached that are based on logical thinking and an analysis of relevant information.

As discussed earlier, the auditor is required to exercise due professional care in all matters related to the audit. The concept of the auditor's exercise of

⁶¹ For a discussion of confirmation bias, see, e.g., Raymond S. Nickerson, *Confirmation Bias: A Ubiquitous Phenomenon in Many Guises*, 2 Review of General Psychology 175 (1998).

professional judgment is rooted in conducting the audit with due professional care. Therefore, the Board retained the phrase “well-reasoned” as proposed. Regarding the degree of documentation related to professional judgment, the auditor is expected to comply with documentation requirements of AS 1215, which includes requirements for considering the nature and extent of documentation needed.

The Board believes that creating a “framework” for how auditors should exercise their professional judgment, as suggested by some commenters, would be beyond the scope of this project. The Board further believes it is better for auditors to adhere to overarching principles and standards that mandate the exercise of professional judgment in connection with conducting an audit with due professional care. This approach acknowledges the multifaceted nature of audits and allows auditors to exercise their professional judgment in the unique circumstances of each audit engagement.

6. Conducting an Audit

i. Auditor and Management Responsibilities

See Paragraph .13 of the New Standard

The Board proposed to require the auditor to plan and perform the audit to obtain sufficient appropriate audit evidence to (a) obtain reasonable assurance about whether: (1) in an audit of financial statements, the financial statements are free of material misstatement, whether due to error or fraud, or (2) in an audit of ICFR, material weaknesses exist as of the date specified in management’s assessment; and (b) provide the auditor with a reasonable basis for forming an opinion. This requirement was retained from AS 1001 and AS 1015 but expanded to cover an audit of ICFR. The Board also proposed to include a note to the requirement that clarified the distinction between the responsibilities of the auditor and those of management, and to expand those responsibilities to include an audit of ICFR. Specifically, the note stated that in an audit of financial statements, the financial statements are management’s responsibility and the auditor’s responsibility is to express an opinion on the financial statements. In an audit of ICFR, management is responsible for maintaining effective ICFR and for assessing the effectiveness of ICFR, and the auditor’s responsibility is to express an opinion on the effectiveness of the company’s ICFR.

Several commenters discussed the importance of clearly distinguishing the responsibilities of the auditor from those of management and suggested retaining the corresponding language from AS 1001.02–.03. For example, one commenter observed that some investors may mistakenly believe that the auditor drafts the financial statements. In the view of this commenter, stating that management is “responsible” for the financial statements may be interpreted as a legal responsibility and does not explicitly convey that management prepares the financial statements.

The Board retained the requirement substantially as proposed. In response to commenters, the Board updated the language in the note to clarify that the financial statements, “including their preparation,” are the responsibility of management and that management is responsible for “establishing and maintaining” effective ICFR.

ii. Reasonable Assurance

See Paragraph.14 of the New Standard

The Board proposed to retain the concept of reasonable assurance from AS 1015. Specifically, the proposed standard stated that reasonable assurance is a high level of assurance and is obtained by reducing audit risk to an appropriately low level through the application of due professional care, including in obtaining sufficient appropriate audit evidence.⁶⁶ The auditor is able to obtain reasonable, but not absolute, assurance that (1) misstatements are detected that, individually or in combination, would result in material misstatement of the financial statements; and (2) in an audit of ICFR, material weaknesses are detected.

Commenters generally supported retaining the concept of reasonable assurance but provided views on its proposed description. A number of commenters, primarily firms, recommended that the Board retain certain statements from AS 1015.10–.13 (or similar language) that describe the limitations of an audit. These statements include:

- Absolute assurance is not attainable because of the nature of audit evidence and the characteristics of fraud. Therefore, an audit conducted in accordance with the standards of the PCAOB may not detect a material weakness in internal control over financial reporting or a material misstatement to the financial statements.⁶⁷

- Even with good faith and integrity, mistakes and errors in judgment can be made [I]n the great majority of cases, the auditor has to rely on evidence that is persuasive rather than convincing.⁶⁸

- Because of the characteristics of fraud, a properly planned and performed audit may not detect a material misstatement.⁶⁹

- [T]he auditor is not an insurer and his or her report does not constitute a guarantee. Therefore, the subsequent discovery that either a material misstatement, whether from error or fraud, exists in the financial statements or a material weakness in internal control over financial reporting exists does not, in and of itself, evidence (a) failure to obtain reasonable assurance, (b) inadequate planning, performance, or judgment, (c) the absence of due professional care, or (d) a failure to comply with the standards of the PCAOB.⁷⁰

A few of these commenters also pointed to the characterization of reasonable assurance in the standards of other standard setters (e.g., ISA 200).⁷¹ These commenters generally expressed concern that without such language, the proposal would reduce transparency and contribute to the expectation gap among investors and other stakeholders regarding the nature of reasonable assurance (as compared to absolute assurance). For example, one commenter stated that the elimination of the existing clarifying language could also result in ambiguity as to whether a new level of assurance would be expected, beyond reasonable assurance but less than absolute assurance.

Some commenters offered other clarifications. For example, two commenters suggested retaining certain language from AS 1001.02, which states that the auditor has no responsibility to plan and perform the audit to obtain reasonable assurance that misstatements, whether caused by errors

⁶⁸ See AS 1015.11.

⁶⁹ See AS 1015.12.

⁷⁰ See AS 1015.13.

⁷¹ Paragraph 13(m) of ISA 200 defines reasonable assurance as “in the context of an audit of financial statements, a high, but not absolute, level of assurance.” Paragraph 5 of ISA 200 further describes that reasonable assurance “is obtained when the auditor has obtained sufficient appropriate audit evidence to reduce audit risk (that is, the risk that the auditor expresses an inappropriate opinion when the financial statements are materially misstated) to an acceptably low level. However, reasonable assurance is not an absolute level of assurance, because there are inherent limitations of an audit which result in most of the audit evidence on which the auditor draws conclusions and bases the auditor’s opinion being persuasive rather than conclusive.”

⁶⁶ See paragraph .03 of AS 1101, *Audit Risk*.

⁶⁷ See AS 1015.10.

or fraud, that are not material to the financial statements are detected. One of these commenters also acknowledged that identifying limitations on the auditor's responsibilities should not be the main focus of the standard. One commenter recommended that the final standard include guidance on determining whether audit risk is reduced to an appropriately low level, including a requirement to consider changes in technology, the nature and quality of an issuer's financial reporting system, relevant academic and other research, and any other factor that can reduce the risk of material misstatements or fraud.

As discussed further below, the Board retained the description of reasonable assurance as proposed with some modifications. The concept of "reasonable assurance" is not new. Reasonable assurance refers to the auditor's degree of satisfaction that the evidence obtained during the audit supports the assertions of the financial statements. It is a high level of assurance and is obtained by reducing audit risk to an appropriately low level (*i.e.*, the risk that the auditor expresses an inappropriate audit opinion when the financial statements are materially misstated or in an audit of ICFR, when a material weakness exists) through applying due professional care, including obtaining sufficient appropriate audit evidence.⁷² AS 1101 discusses audit risk and the relationships among the various components of audit risk in an audit of financial statements. The Board retained a reference to AS 1101 in the final standard and added the description of the term "audit risk." The Board believes that additional guidance on consideration of audit risk, as suggested by one commenter, is outside the scope of this standard. If additional guidance is necessary regarding the auditor's assessment of and response to the risks of material misstatement in an audit, it would be provided in connection with the Board's risk assessment standards.⁷³

The Board did not change the meaning of reasonable assurance or the requirement to obtain reasonable assurance. In consideration of comments received, the Board emphasized in the final requirement that reasonable assurance is not absolute assurance. As observed by some commenters, absolute assurance is not attainable because of the nature of audit evidence (*e.g.*, selective testing

involving professional judgments⁷⁴ regarding the nature, timing, and extent of procedures to be performed; and inherent uncertainty of accounting estimates), and the characteristics of fraud (*e.g.*, falsified company documentation). In many cases, the auditor has to rely on evidence that is persuasive rather than convincing. Because the Board did not change the meaning of reasonable assurance, the Board believes that further explanation of the difference between reasonable assurance and absolute assurance is not needed in the final standard.

The Board did not retain additional descriptions of the inherent limitations of an audit from AS 1015.10–.13. The Board believes that these matters are part of the differences between reasonable and absolute assurance discussed above or addressed elsewhere in PCAOB standards. Although a properly planned and performed audit may not detect a material misstatement because of the characteristics of fraud, that does not diminish the auditor's responsibility to plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud.

iii. Compliance With Applicable Professional and Legal Requirements

See Paragraph .15 of the New Standard

The Board proposed to require that the auditor comply with applicable professional and legal requirements in conducting the audit. As discussed above, the term "applicable professional and legal requirements" was proposed to have the same meaning as defined in proposed QC 1000. Under existing provisions, auditors are required to comply with PCAOB standards and rules. The proposed requirement emphasized that the overall objective of the auditor is achieved by complying with more than just the standards of the PCAOB. This includes compliance with requirements of Section 10A of the Exchange Act related to illegal acts, related party transactions, and an evaluation of whether there is substantial doubt about the ability of the company to continue as a going concern.⁷⁵ The proposed requirement also stated that, in fulfilling these requirements, the auditor should keep in mind its role in protecting investors.

One commenter on this proposed paragraph stated that the term "applicable professional and legal requirements" appears to exceed the

Board's authority, citing Sections 104 and 105 of Sarbanes-Oxley and urged that the Board replace it with "PCAOB rules and standards." Two other commenters noted that applicable professional and legal requirements could be read broadly as a wide range of laws and regulations that do not directly bear on the conduct of audit engagements. Another commenter recommended adding clarifying language in the release to state that although the auditor is expected to comply with applicable legal requirements, the auditor is not expected to have the expertise of a lawyer or to express opinions on matters of law.

The Board disagrees with the commenter's assertions regarding the Board's authority, which extends beyond PCAOB rules and standards. For example, Section 105(c)(4) of Sarbanes-Oxley empowers the Board to sanction a registered firm and its associated persons for violations not only of PCAOB rules and standards but also violations of "the provisions of the securities laws relating to the preparation and issuance of audit reports and the obligations and liabilities of accountants with respect thereto, including the rules of the Commission issued under [the] Act[.]"

As discussed above, the final standard includes a definition of the term "applicable professional and legal requirements" rather than a reference to the definition in QC 1000. The definition that was proposed in the QC 1000 project has been modified in response to comments received in that rulemaking, to explicitly mention ethics laws and regulations. The definition was also refined to limit the breadth of the term, by clarifying that it encompasses statutory, regulatory, and other legal requirements beyond professional standards and other PCAOB rules "[t]o the extent related to the obligations and responsibilities of accountants or auditors in the conduct of engagements or in relation to the quality control system." The Board believes that further changes to this term in the final standard are not necessary.

As discussed above, the Board changed "expertise" to "proficiency" in the final description of competence in response to comments. While the Board does not expect auditors to have the expertise of a lawyer, the Board believes that understanding the company's business and being proficient in the rules and regulations relevant to the company under audit and the related industry is important.

⁷² See AS 1101.03–.04.

⁷³ See, *e.g.*, AS 1101, AS 2101, AS 2105, AS 2110, and AS 2301.

⁷⁴ The discussion above describes requirements for exercising professional judgment.

⁷⁵ 15 U.S.C. 78j–1.

Some commenters also stated that the requirement for auditors to “keep in mind their role in protecting investors” when fulfilling the requirement to comply with applicable professional and legal requirements was unclear, including how to apply such a requirement. As discussed above, investor-related groups suggested including the language from the *Arthur Young opinion* to describe the auditor’s responsibility. Other commenters suggested that the proposed reference to the auditor’s role in protecting investors be deleted from the final requirement or reframed. One commenter pointed to research noting that encouraging auditors to adopt an investor perspective when making judgments may be detrimental to audit quality.⁷⁶

After considering comments and for the reasons discussed above, the Board retained the requirement to comply with applicable professional and legal requirements. The Board removed the reference to “keep in mind their role in protecting investors” from the final standard based on changes made to paragraph .01 of the final standard. As discussed earlier, in connection with certain revisions made to the introductory paragraph of the final standard, the Board added a note to paragraph .01 to remind auditors that their obligation to protect investors is important when complying with all requirements of this and other PCAOB standards and rules.

iv. Relevant Guidance

See Paragraph .15 of the New Standard

The Board also proposed a note to paragraph .15 stating that, as part of complying with all applicable professional and legal requirements in conducting the audit, the auditor is required to take into account relevant guidance applicable to the audit. The proposed requirement was an extension of the existing requirement in AS 1001.11 that the auditor be aware of and consider auditing interpretations issued by the AICPA as of 2003, and adopted by the PCAOB and in effect. Under the proposal, relevant guidance included PCAOB auditing interpretations, Board-issued guidance, and releases that accompany the rules and standards of the Board.

Many commenters, mostly firms and firm-related groups, expressed concern

⁷⁶ This commenter cited two research papers: (i) Altiero, Kang, and Peecher (2022) “show that auditors prompted to take an investor perspective are less likely to assess a misstatement as material” and (ii) Dong, Wang, and Chien (2022) “highlight that taking an investor perspective can decrease assessed risk of material misstatement.” See additional discussion below.

that the proposed note is overly broad and unclear. For example, some commenters cited a lack of clarity as to (i) the scope of the Board-issued guidance including whether documents such as concept releases would be covered; (ii) the timeline in which the requirement would apply; (iii) the hierarchy of guidance and what types of guidance would be considered authoritative; and (iv) how to reconcile potentially conflicting information between proposing and final releases. These commenters generally suggested either deleting the note, codifying the relevant guidance to ensure consistent application, or specifying that relevant guidance includes releases accompanying “final” standards. Another commenter also suggested clarifying the meaning of “take into account,” including defining the phrase in PCAOB Rule 3101.

A few commenters, including an investor-related group, recommended including relevant guidance within the standard rather than the accompanying release. Two commenters suggested that the Board consider restructuring guidance in a manner similar to the application and other explanatory material, as presented in the AICPA and IAASB standards. An investor-related group recommended a “codification” approach that would include placing all guidance, interpretations, releases, amendments, and rules in the same location.

After considering comments received, the Board revised the note as follows:

- Replaced the reference to “relevant guidance” with “PCAOB auditing interpretations”; and
- Replaced a footnote describing the scope of the relevant guidance with a footnote describing the scope of PCAOB auditing interpretations.

The note in the final standard provides that, when complying with PCAOB standards, the auditor is required to also take into account PCAOB auditing interpretations applicable to the audit. As mentioned previously, this is an existing requirement that is being carried forward with modifications. In the final standard, PCAOB auditing interpretations refer to the PCAOB publications entitled “Auditing Interpretations” as currently in effect.⁷⁷ These interpretations were originally adopted by the Board in 2003 along with the interim standards. Since that time, certain of these auditing

⁷⁷ PCAOB auditing interpretations do not include independence interpretations. The requirements to comply with independence interpretations are covered by PCAOB Rule 3500T, *Interim Ethics and Independence Standards*.

interpretations have been and continue to be revised or rescinded in connection with the other amendments to PCAOB standards. The requirement in the final standard, as it did previously, relates to the interpretations currently in effect.

Apart from the PCAOB auditing interpretations referenced in paragraph .15, the PCAOB also supports the implementation of and compliance with its standards in many other ways, including providing guidance in rulemaking releases that accompany standards, amendments, or rules, or issuing staff guidance.⁷⁸ Although there is no requirement to follow these guidance documents, the Board continues to believe that it is important for auditors to pay attention to such guidance, if relevant, when conducting an audit in accordance with PCAOB standards because it may help the auditor understand and comply with complex provisions of those standards or rules. For example, staff guidance can help auditors better understand how the PCAOB intends to implement, inspect against, or enforce existing rules and standards.

The phrase “take into account” in the rule text is not new. It has been used previously in PCAOB standards in reference to information or matters that the auditor should think about or give attention to in performing an audit procedure or reaching a conclusion.⁷⁹ Accordingly, the results of the auditor’s thinking on the relevant matters should be reflected in the performance and documentation of the respective audit procedure performed or conclusion reached.

Lastly, the Board did not consider the “codification” approach because it is out of scope for this project.

v. Audit Documentation

See Paragraph .16 of the New Standard

The Board proposed to require the auditor to prepare audit documentation in accordance with AS 1215. This requirement was intended to emphasize the importance of adequate audit documentation to planning and performing the audit and to the supervision and review of work performed during the audit. Commenters did not express concerns

⁷⁸ PCAOB staff prepares guidance to assist in the implementation of PCAOB standards and rules. The typical legend on such guidance states that the document represents the views of PCAOB staff and not necessarily those of the Board, and that the document is not a rule, policy, or statement of the Board. PCAOB staff audit practice alerts are examples of staff guidance that highlight new, emerging, or otherwise noteworthy circumstances that may affect how auditors conduct audits under existing PCAOB standards.

⁷⁹ See, e.g., AS 3101.12 and AS 2501.

with the documentation requirement, and the Board adopted it as proposed.

vi. Auditor Communications

See Paragraphs .17 Through .20 of the New Standard

The Board proposed an explicit requirement for the auditor's report to contain (i) an expression of opinion on the financial statements, taken as a whole, or an assertion that an opinion cannot be expressed; and (ii) in an audit of internal control over financial reporting, an expression of opinion on the effectiveness of the company's internal control over financial reporting or an assertion that an opinion cannot be expressed. Under the proposed standard, the auditor would be in a position to express an unqualified opinion only when the auditor has performed the audit in accordance with standards of the PCAOB and has obtained sufficient appropriate audit evidence to conclude that: (i) in an audit of financial statements, the financial statements, taken as a whole, are presented fairly, in all material respects, in conformity with the applicable financial reporting framework; and (ii) in an audit of internal control over financial reporting, the company maintained, in all material respects, effective internal control over financial reporting. The proposal also briefly addressed when circumstances require an auditor to express a qualified opinion, adverse opinion, or disclaimer of opinion and referred to AS 3105 and AS 2201 for a description of those circumstances. The proposed requirements were retained from AS 1001 with modifications to be consistent with provisions of AS 3101 and AS 2201.

One investor-related group requested that the required communications include CAMs, and that paragraph .17a of the proposed standard be revised to refer to CAMs "as a 'must contain' item in the auditor's report." The commenter was concerned with the low numbers of CAMs in auditor's reports and that auditors treat the determination of CAMs as "nearly a 'check the box' exercise." Another commenter suggested edits to proposed paragraphs .17 and .19 to align with existing requirements (e.g., adding the phrase "In an audit of financial statements" to paragraph .17a and moving the phrase "the company's" within paragraph .19).

The Board adopted paragraphs .17–.19 substantially as proposed with some modifications. After considering the comments received, the reference to CAMs in a footnote has been moved to a note to paragraph .17 to emphasize the

importance of CAMs. The Board did not make any additional changes to address concerns regarding CAMs. The proposal was not designed to address concerns about the frequency or informative quality of CAMs. Although the Board understands the importance of the concern raised by commenters, this is outside the scope of this project. The Board also revised paragraph .17a and paragraph .19 to incorporate commenters' suggestions described above. Additionally, the Board changed the phrase "modify the report" to "depart from an unqualified opinion" in paragraph .19 to align with other Board-issued standards that describe reports that include opinions other than an unqualified opinion.⁸⁰

The Board proposed in paragraph .20 to require that the auditor communicate externally in accordance with applicable professional and legal requirements. This is an overarching requirement to communicate externally that is based on existing auditor communication requirements (e.g., AS 1301). The Board did not receive any comments on this requirement and are adopting it with slight modification. The Board changed "as required by" to "in accordance with" applicable professional and legal requirements to align with similar phrases used in other Board-issued standards.

Amendments Related to AS 1000

The amendments the Board adopted are described below.

1. Amendments to AS 2810 and Rescission of AS 2815

The Board proposed to incorporate into AS 2810 the requirements of AS 2815 regarding the determination of whether the financial statements are presented fairly in conformity with the applicable financial reporting framework for a more logical presentation, and to rescind AS 2815. Currently, AS 2810 requires the auditor to evaluate whether the financial statements are presented fairly, in all material respects, in conformity with the applicable financial reporting framework, and AS 2815 describes the meaning of this evaluation. The proposed approach was intended to streamline these requirements into one standard and eliminate redundant or unnecessary language. A number of commenters commented on the proposed amendments to AS 2810. After considering the comments received, the Board adopted amendments to AS 2810 with certain modifications discussed below.

i. Clarifying the Meaning of "Present Fairly"

The discussion in the proposing release was designed to clarify the auditor's existing obligation to evaluate the fairness of the financial statements in conformity with the applicable financial reporting framework by stating that "present fairly," under extant PCAOB standards, is a concept that goes beyond mere technical compliance with the requirements of the applicable financial reporting framework.

Some commenters, primarily investor-related groups, supported clarifying the meaning of "present fairly" and provided additional suggestions on amendments to AS 2810. Two investor-related groups suggested that the Board consider going further and require auditors to focus on whether the financial statements are a fair presentation of the company's position rather than narrowly focusing on whether the company is following U.S. GAAP. One investor-related group suggested adding the word "and" immediately before the phrase "in conformity" to make it clear that there is an expectation that the financials are presented fairly, in all material respects *in addition to* conforming with the applicable financial reporting framework. Another group said that auditors should aid in disclosing and providing transparency around the sensitivity and accuracy of climate-related estimates and assumptions.

Other commenters, primarily firms and firm-related groups, viewed the proposed amendments as an expansion of auditors' existing responsibilities. Some commenters asserted that the statement in the proposal that the auditor's judgments concerning the fair presentation of the financial statements go beyond compliance with the applicable financial reporting framework may create a conflict between the auditor's judgment and management's judgment and introduce potential inconsistency in accounting treatment. Others expressed concern that under the proposal, auditors would expect the company to override the requirements of an applicable financial reporting framework if the financial statements prepared in accordance with the framework did not fairly present the substance of the company's financial results.

Some commenters suggested retaining language from AS 2815.03 which states, "The independent auditor's judgment concerning the 'fairness' of the overall presentation of financial statements should be applied within the framework of generally accepted accounting

⁸⁰ See, e.g., AS 3105.

principles. Without that framework, the auditor would have no uniform standard for judging the presentation of financial position, results of operations, and cash flows in financial statements.” Other commenters suggested explicitly retaining the concept of professional judgment for evaluation of fair presentation.

The Board’s proposed clarification of “present fairly” was not intended to change the auditor’s existing responsibilities for the evaluation of whether the financial statements are presented fairly in conformity with the applicable financial reporting framework.

First, the amendments to AS 2810 clarify that “presents fairly” involves evaluating whether information in the financial statements is presented and classified appropriately and in a manner that is not misleading, and that this evaluation is made within the applicable financial reporting framework. Contrary to the views of some commenters, the amendments do not require auditors to expect that the company override or deviate from the requirements of the applicable financial reporting framework. Any override or deviation from the requirements of the applicable financial reporting framework would normally result in a departure from an unqualified opinion under PCAOB standards.⁸¹ Further, the auditor is required to evaluate the risk of omitted, incomplete, or inaccurate disclosures as part of the auditor’s risk assessment procedures.⁸²

Second, the amendments acknowledge that applicable financial reporting frameworks recognize that additional disclosures may be needed to ensure fair presentation. For example, as noted above, the SEC requires by rule that a company provide further material information as necessary to make any required statements, in the light of the

circumstances under which they are made, not misleading.⁸³ This obligation is also consistent with the accounting standards issued by the FASB⁸⁴ and International Accounting Standards Board (“IASB”).⁸⁵ Thus, when the auditor evaluates whether company transactions have been recorded and presented in conformity with the applicable financial reporting framework, the auditor may determine that additional company disclosures are needed to better reflect the substance of the transactions. Such evaluation is currently required under both AS 2810.31 and AS 2815.06, and the

⁸³ See 17 CFR 210.4–01(a) (Regulation S–X Rule 4–01(a)).

⁸⁴ See, e.g., FASB Accounting Standards Codification (“FASB ASC”) paragraph 105–10–05–1, Generally Accepted Accounting Principles—Overall—Overview and Background (“Rules and interpretive releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants.”); FASB ASC paragraph 235–10–05–3, Presentation—Notes to Financial Statements—Overall—Overview and Background—Importance of Accounting Policies Disclosure (“The accounting policies of an entity are the specific accounting principles and the methods of applying those principles that are judged by the management of the entity to be the most appropriate in the circumstances to present fairly financial position, cash flows, and results of operations in accordance with generally accepted accounting principles (GAAP) and that, accordingly, have been adopted for preparing the financial statements.”).

⁸⁵ See, e.g., IASB International Accounting Standards (“IAS”) 1, paragraph 15, Presentation of Financial Statements—Financial Statements—General features—Fair presentation and compliance with IFRSs (“Financial statements shall present fairly the financial position, financial performance and cash flows of an entity. Fair presentation requires the faithful representation of the effects of transactions, other events and conditions in accordance with the definitions and recognition criteria for assets, liabilities, income and expenses set out in the *Conceptual Framework for Financial Reporting (Conceptual Framework)*. The application of IFRSs, with additional disclosure when necessary, is presumed to result in financial statements that achieve a fair presentation.”); IAS 1, paragraphs 19–24, Presentation of Financial Statements—Financial Statements—General features—Fair presentation and compliance with IFRSs (describing financial reporting responsibilities in the “extremely rare circumstances in which management concludes that compliance with a requirement in an IFRS would be so misleading that it would conflict with the objective of financial statements set out in the *Conceptual Framework*”); IAS 8, paragraph 10, Accounting Policies, Changes in Accounting Estimates and Errors (“In the absence of an IFRS that specifically applies to a transaction, other event or condition, management shall use its judgement in developing and applying an accounting policy that results in information that is: (a) relevant to the economic decision-making needs of users; and (b) reliable, in that the financial statements: (i) represent faithfully the financial position, financial performance and cash flows of the entity; (ii) reflect the economic substance of transactions, other events and conditions, and not merely the legal form; (iii) are neutral, ie free from bias; (iv) are prudent; and (v) are complete in all material respects.”).

requirement is retained in the amendments to AS 2810.30A and .31.

In response to commenters, the Board retained, in the first note to AS 2810.30, the language of AS 2815.03, with some modifications. Specifically, the Board revised the reference to “generally accepted accounting principles” to “applicable financial reporting framework.” The Board rephrased the sentence to emphasize that the “applicable financial reporting framework provides the basis for the auditor’s judgment regarding the presentation of financial position, results of operations, cash flows, and disclosures in financial statements.” The Board also agrees with commenters that the auditor’s evaluation of fairness of presentation of the financial statements is an exercise of professional judgment in the context of an applicable financial reporting framework. The first note to AS 2810.30 refers to the auditor’s judgment when evaluating the fairness of the overall presentation of financial statements.

The Board also added a new footnote to paragraph .30A, as discussed below, referencing SEC Rule 4–01(a) that describes the company’s obligation regarding additional information that may need to be disclosed in the financial statements so that the financial statements are not misleading.

ii. References to SEC Rule 12b–20

The proposed amendment to AS 2810.30 included a new footnote 17A that referred to a company’s responsibility pursuant to SEC Rule 12b–20 under the Exchange Act, 17 CFR 240.12b–20 (“SEC Rule 12b–20”). That rule requires the company to disclose “such further material information, if any, as may be necessary to make the required statements, in the light of the circumstances under which they are made not misleading.”

Most commenters who addressed the proposed citation to SEC Rule 12b–20 expressed concern with it. While one investor-related group recommended relocating the proposed footnote to the body of the amendments due to its significance, other commenters suggested removing the reference to SEC Rule 12b–20, with some commenters objecting primarily because the rule pertains to companies’ disclosures within or beyond the financial statements. Some commenters emphasized that disclosures beyond the financial statements are the responsibility of companies rather than of auditors. Many expressed concerns that referring to the rule might be viewed as expanding the auditor’s responsibilities, or would conflict with

⁸¹ See AS 3105. In addition, under SEC rules, a company’s “[f]inancial statements filed with the Commission which are not prepared in accordance with generally accepted accounting principles will be presumed to be misleading or inaccurate, despite footnote or other disclosures, unless the Commission has otherwise provided.” 17 CFR 210.4–01(a)(1) (Regulation S–X Rule 4–01(a)(1)). Paragraph (a) of that rule also provides that “the information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further material information as is necessary to make the required statements, in the light of the circumstances under which they are made, not misleading.”

⁸² See, e.g., AS 2110.67, which requires the auditor, as part of the auditor’s evaluation of fraud risk factors, to include evaluation of how fraud could be perpetrated or concealed by presenting incomplete or inaccurate disclosures or omitting disclosures that are necessary for the financial statements to be presented fairly in conformity with the applicable financial reporting framework.

the auditor's responsibilities described in AS 3101.08e.⁸⁶ One of these commenters suggested citing SEC Rule 4–01(a)(1) instead, because that rule relates specifically to financial statements, upon which the auditor expresses an opinion.

After considering the comments received, the Board deleted proposed footnote 17A with the reference to SEC Rule 12b–20 from the final amendment to AS 2810.30 because that rule reflects a company's responsibilities for information beyond as well as within the financial statements.⁸⁷ Instead, the Board retained the existing note to that paragraph requiring that the auditor look to the requirements of the SEC for the company under audit with respect to the accounting principles applicable to that company. The requirements of the SEC for the company under audit are included in SEC Rule 4–01(a), which the Board referenced in a new footnote to paragraph .30A, to remind auditors of the company's obligation regarding additional information that may need to be disclosed in the financial statements so that the financial statements are not misleading.

iii. Other Clarifications To Proposed AS 2810.30A

The Board proposed a new paragraph AS 2810.30A based on the extant requirement from AS 2815.04, using language consistent with other PCAOB standards. Specifically, the Board:

- Combined the concepts in AS 2815.04a–b regarding acceptability and appropriateness of accounting principles and presented them in AS 2810.30Ab;
- Retained the concepts from AS 2815.04c–d regarding informativeness of information presented in the financial statements and presented them as a new AS 2810.30Aa; and
- Retained the concepts from AS 2815.04e regarding transactions presented in the financial statements within a range of acceptable limits as a new AS 2810.30Ac and an amendment to AS 2810.31.

Several commenters expressed concern about not retaining the reference to the “within a range of

acceptable limits” from AS 2815 and suggested (i) retaining this phrase in AS 2810.30A or (ii) revising proposed 2810.30A to include a footnote referencing AS 2110 or a note describing the relationship between AS 2810.30A and AS 2110 and adding “in all material respects” to AS 2810.30Ac. Another commenter suggested defining “a reasonable investor” used in AS 2810.30Aa. One commenter encouraged the Board to provide guidance on the use of the term “informative” in AS 2810.30A because it could be widely interpreted and applied in practice.

In addition, several commenters suggested including or clarifying certain terminology or concepts used in the proposed new paragraph, AS 2810.30A. Suggestions included:

- Referencing the importance of exercising professional judgment when evaluating the requirements specified in AS 2810.30A; and
- Clarifying that (i) “financial statements” include all notes to the statements and all related schedules;⁸⁸ and (ii) “disclosures” used in AS 2810.30A means “accompanying notes,” not other information included in management discussion and analysis (“MD&A”) and other disclosures included in the annual report.

After considering the comments received, the Board retained proposed paragraph .30A with modifications discussed below.

The final AS 2810.30A requires an auditor, when evaluating whether the financial statements (including the accompanying notes) present fairly the financial position, results of operations, and cash flows, in all material respects, in conformity with the applicable financial reporting framework, to evaluate whether:

- a. The financial statements are informative of matters that may affect their use, understanding, and interpretation; and the information in the financial statements is presented and classified appropriately and in a manner that is not misleading;
- b. The accounting principles selected and applied by the company's management are appropriate in the circumstances; and
- c. Company transactions and relevant events and conditions are appropriately recognized, measured, and disclosed in the financial statements.

The Board added “(including the accompanying notes)” in AS 2810.30A to clarify that financial statements include the accompanying notes, to match the description in AS 2810.31 of

financial statements as “financial statements (including the accompanying notes).” Because the Board uses “disclosures” as an interchangeable term with “notes” or “accompanying notes” throughout PCAOB standards, it is unnecessary to further clarify the terms in AS 2810.30A. The Board also did not add a reference to professional judgment in AS 2810.30A, but as discussed above the Board revised the first note to AS 2810.30 to clarify that the auditor uses professional judgment when evaluating the fairness of financial statements.

The term “informative” is in AS 2815.04c, which refers to AS 2810.31, which in turn provides additional considerations for evaluation of information disclosed in the financial statements (*e.g.*, consideration of the form, arrangement, and the amount of detail given). To clarify this further, the Board retained in the final standard language from AS 2815.04c stating that the information in the financial statements is presented appropriately, in a manner that is “informative of matters that may affect their use, understanding and interpretation” and not misleading. The Board removed the reference to “reasonable investor” from AS 2810.30A because it was limiting and did not consider a broader population of financial statement users (*e.g.*, creditors). The Board also believes that introducing “reasonable investor” in AS 2810.30A may create confusion by implying that an analysis is needed that is distinct from determining if the financial statements are presented fairly in conformity with the applicable financial reporting framework.

Finally, the Board does not believe it is necessary to retain a reference to “within a range of acceptable limits” in AS 2810.30A. The standard is clear that evaluation of fairness is based on auditor judgment and that the concept of materiality is inherent in that judgment, which involves the consideration of qualitative as well as quantitative factors. The combination of these considerations should be clear that not every transaction or account is evaluated to arrive at the conclusion that the company's financial statements, taken as a whole, are presented fairly, in all material respects.

iv. Other Clarifications to Proposed AS 2810.31

The Board proposed to revise the note to AS 2810.31 by (i) removing the first sentence that describes the requirements from AS 3105 (*i.e.*, inadequate disclosures) and instead adding a reference to AS 3105.24–.27 in paragraph .31, and (ii) adding an extant

⁸⁶ AS 3101.08e requires that the auditor's report include an opinion that the financial statements present fairly, in all material respects, the financial position of the company, results of operations, and cash flows in conformity with the applicable financial reporting framework, and that the opinion identify the applicable financial reporting framework.

⁸⁷ The auditor's responsibility for other information outside of the financial statements is specified in AS 2710, *Other Information in Documents Containing Audited Financial Statements*.

⁸⁸ See 17 CFR 210.1–01(b) (Regulation S–X Rule 1–01(b)).

requirement from AS 2815.06 for the auditor to also evaluate whether the substance of transaction or events differs materially from their form, but changing it from “should consider” to “should evaluate.”

Several commenters suggested, in addition to retaining the requirement from AS 2815.06, to also retain a provision from AS 2815.06 that states “generally accepted accounting principles recognize the importance of reporting transactions and events in accordance with their substance.” Some commenters suggested not changing the “should consider” requirement from extant AS 2815.06 to “should evaluate” when evaluating a transaction in substance over form. Additionally, some commenters recommended removing or relocating the note in AS 2810.31 to proposed AS 2810.30A for better context.

Two investor-related groups suggested providing guidance on AS 2810.31 by adding the existing concept of what the auditors are required to do (per AS 2815.04c) when the applicable financial reporting framework does not provide guidance (e.g., financial statements and accompanying notes do not disclose the necessary information required), or what considerations should be given by auditors in evaluating fair presentation of financial statements in accordance with proposed AS 2810.30.

After considering the comments received, rather than amending the existing note to AS 2810.31, the Board removed the note in its entirety. The Board believes that a separate requirement to evaluate whether the substance of transactions differs from their form is unnecessary in light of the requirement in new AS 2810.30Aa. As discussed above, AS 2810.30Aa requires auditors to evaluate “whether the financial statements are informative of matters that may affect their use, understanding, and interpretation;” and the information in the financial statements is presented and classified appropriately and in a manner that is not misleading. This evaluation includes determining whether additional disclosures are necessary to reflect, for example, the substance of the company’s transactions. The auditor’s evaluation of whether company transactions have been recorded and presented in conformity with the applicable financial reporting framework includes the determination of whether additional disclosures are needed in the financial statements.

The Board also believes that AS 2810.31 and the amendments are comprehensive and clear, and thus no additional guidance is warranted. For

example, under US GAAP and IFRS, management has a range of conforming choices in selecting classifications and measurements of revenue recognition, segment reporting, and fair value measurement. The auditor is responsible for evaluating whether the disclosures reflect the choices made by management and are not misleading to investors and other financial statement users.

2. Amendments Related to Engagement Partner Responsibilities for Supervision

i. Seeking Assistance From Other Engagement Team Members

AS 1201 and AS 2101 establish the engagement partner’s responsibility for the engagement and its performance, including planning, supervision, and review. The Board proposed to amend the existing requirements in AS 1201 and AS 2101 to clarify that even when the engagement partner seeks assistance from other engagement team members, the engagement partner retains the primary responsibility for the engagement and its performance. One commenter strongly supported these amendments, and the Board adopted them as proposed.

The final notes added to AS 1201 and AS 2101 clarify that while an engagement partner may seek assistance on specific tasks from other engagement team members, they continue to retain the primary responsibility for supervising, reviewing, and ensuring the quality of the work performed in the audit. In other words, the work of other engagement team members does not replace or reduce the engagement partner’s responsibility for the engagement and its performance.

ii. Timing of review

The Board also proposed a requirement to clarify that the review and evaluation by the engagement partner (and as applicable by other engagement team members performing supervisory activities) of work performed by engagement team members, as described in AS 1201.05c, must be completed prior to the report release date. These amendments did not receive any comment and are being adopted as proposed.

iii. Workpaper Review

The Board proposed to amend AS 1201 to clarify the extent of the planning, supervisory, review, and documentation activities to be performed by the engagement partner by aligning those activities with existing auditor responsibilities under AS 1015 because the Board believes that the engagement partner’s review of audit

documentation is an important part of supervision. These amendments were intended to reaffirm the engagement partner’s supervisory and review responsibilities in the context of exercising due professional care.⁸⁹ Specifically, the Board proposed to add a note stating that notwithstanding assistance from other engagement team members performing supervisory activities, the engagement partner is required to review sufficient documentation to determine that (i) the engagement was performed as planned; (ii) significant judgments were appropriate and significant findings and issues, along with matters brought to the engagement partner’s attention pursuant to AS 1201.05b, were appropriately addressed; (iii) the conclusions expressed in the auditor’s report are appropriate and supported by sufficient appropriate evidence; and (iv) matters requiring communication under applicable professional and legal requirements are appropriately identified and communicated. The proposed note also provided that the engagement partner’s review includes review of documentation of significant findings or issues⁹⁰ and review of documentation that is also subject to review by the EQR, citing the provisions of AS 1220 that specifically require the EQR to review certain documentation.⁹¹

One commenter stated that the proposed amendments were overly prescriptive and should allow more flexibility regarding the engagement partner’s review and sign-off. Another commenter recommended clarifying how due professional care in AS 1201 relates to the engagement partner’s responsibilities in AS 1000. This commenter further recommended better aligning AS 1201 with proposed AS 1000.09, including the interplay between Note 2 of AS 1201.05, which has specific workpaper review requirements by the engagement partner, while AS 1201.04 also allows the engagement partner to seek assistance from other engagement team members.

After considering the comments received, the Board adopted amendments to AS 1201 substantially as proposed. The Board believes that the amendments clarify the engagement partner’s existing obligations for supervision and review. As the engagement team member with primary responsibility for the engagement, the engagement partner must review, at minimum, sufficient documentation of

⁸⁹ See AS 1000.10 discussed above.

⁹⁰ See AS 1215.12.

⁹¹ See AS 1220.09–.10 and .14–.15.

specific audit areas that are deemed important to support the auditor's opinion. Without reviewing sufficient documentation in these areas, the engagement partner would not be able to demonstrate that the engagement partner has the primary responsibility for the audit.

One commenter asserted that the proposed requirement that the "engagement partner's review should include review of documentation . . . subject to review by the engagement quality reviewer" could be interpreted to require the engagement partner to review all documentation reviewed by the EQR, beyond what is required in AS 1220.10 or .15. Another commenter expressed concern about the proposed note stating that in multi-tiered audits, other audit partners, not only the engagement partner, should retain the ability to review all documentation subject to EQR review. This commenter suggested not linking engagement partner review requirements to documentation subject to review by EQR.

In response to the commenters, the Board clarified the final requirement by changing the phrase "review of documentation subject to review by the engagement quality reviewer" to "review of documentation required to be reviewed by the engagement quality reviewer pursuant to the requirements of paragraphs .09–.10 and .14–.15 of AS 1220 . . ." This revision further clarifies that the Board expects the engagement partner to review the documentation that the engagement quality reviewer is required to review in order to comply with those provisions of AS 1220, rather than all of the documentation that the engagement quality reviewer may have actually reviewed. The Board believes that the documentation of significant judgments made and conclusions reached by the engagement team that is required to be reviewed by the EQR provides important information to the engagement partner. This is true for all engagements, including multi-location and multi-tiered engagements. The extent of documentation reviewed by the EQR and, under the final amendment, by the engagement partner, will depend on the facts and circumstances of the particular engagement. Further, the requirement for the engagement partner to review documentation required to be reviewed by the EQR does not preclude other engagement team members performing supervisory activities to also review this documentation.

Several commenters further expressed concerns that the proposed amendments

create an incorrect perception that the responsibility for all phases of the audit resides with the engagement partner only without any consideration given to the responsibility of the firm or other engagement team members. One of these commenters further suggested including a statement that the engagement partner should tailor the extent of their supervision based on a variety of factors as described in AS 1201.06. AS 1201.05 specifically addresses the responsibilities of the engagement partner relating to supervision of engagement team members, and the Board does not think it is necessary to change these requirements to address the responsibilities of others.

One commenter stated that the engagement partner's review of documentation to determine that the engagement was performed as planned may be construed as expanding the partner review requirements beyond AS 1215.12c because the review of documentation only relates to "results of auditing procedures that indicate a need for significant modification of planned auditing procedures." The Board does not believe that Note 2 of AS 1201.05 expands the engagement partner's responsibilities. AS 2101.03 states that the engagement partner is responsible for planning the audit and that the engagement partner retains primary responsibility for the engagement and its performance. In addition, the documentation requirements under AS 1215 are not limited to the significant findings and issues described in AS 1215.12 and there are other documentation requirements outside of documenting specific matters.

Another commenter further suggested that the Board define "sufficient documentation" used in proposed Note 2 of AS 1201.05. The Board does not believe this is necessary. What is sufficient will depend on the facts and circumstances of the particular engagement under review. The amount of documentation that the engagement partner would review will vary depending on the associated risk involved in the audit area and the nature of the work performed that the engagement partner reviews. The Board further clarified this point, by changing "sufficient documentation to determine" to "documentation sufficient to determine" in the final amendment. This change is designed to better connect the concept of sufficiency with the matters that the engagement partner will determine.

The Board also proposed other amendments to AS 1201 and AS 2101 to conform to the adoption of AS 1000.

These technical and clarifying amendments included replacing references to titles of existing standards with the title of the new standard and updating cross-referenced terminology and paragraph citations. The Board adopted these other amendments as proposed as no comments were received.

3. Amendments Related to Documentation

The Board proposed several amendments to AS 1215 discussed in more detail below. Commenters generally supported the proposed amendments to AS 1215. Some commenters provided specific comments related to (i) documentation completion date and (ii) specific audit documentation and timing for documentation review. These are discussed in more detail below.

i. Documentation Completion Date

Audit documentation is the written record of the basis for the auditor's conclusions that provides the support for the auditor's representations, whether those representations are contained in the auditor's report or otherwise. Audit documentation also facilitates the planning, performance, and supervision of the engagement, and is the basis for the review of the quality of the work because it provides the reviewer with written documentation of the evidence supporting the auditor's significant conclusions.⁹² Under existing standards, a complete and final set of audit documentation is required to be assembled for retention as of a date not more than 45 days after the report release date, known as the documentation completion date.⁹³ The Board proposed to accelerate the documentation completion date by reducing the maximum period from 45 days to 14 days.

Many commenters who addressed the amendment generally supported it or agreed that the proposed acceleration of the documentation completion date would be appropriate or result in increased audit quality. Two commenters further stated that the shorter period of 14 days would not cause significant changes at most firms.

Several commenters raised concerns over the acceleration of the documentation completion date. One commenter stated that the acceleration would likely lead to more audit quality issues due to the increasingly more complex financial accounting, reporting, and auditing landscape requiring more

⁹² See AS 1215.02.

⁹³ See AS 1215.15.

time as well as the current talent crisis. Another commenter stated that 14 days is too short to handle any unforeseen consequences (*e.g.*, technology interruptions). Another commenter questioned whether acceleration of documentation will (i) have any meaningful impact on PCAOB inspection timelines and operating efficiencies and (ii) be workable for smaller firms, who may not have the technology to implement this change.

Two commenters, both investor-related groups, recommended further shortening the documentation completion date to two days because an earlier PCAOB inspection would benefit investors. These two investor-related groups and another commenter questioned why 14 days is a more appropriate timeframe. Focusing on challenges that smaller firms may face in implementing the acceleration, and the diversity across global network firms in documentation archive systems, several commenters recommended a phased implementation approach or extending the implementation over a longer period (*e.g.*, two-year period).

The proposal also sought comment, in light of the proposed 14-day documentation completion date, on whether firms would have difficulty, when filing Form AP within 35 days of the audit report being filed, complying with AS 1215.16. That paragraph of AS 1215 prohibits the deletion or discarding of audit documentation after the documentation completion date but permits the addition of documentation under certain conditions. Two firms stated that they did not foresee significant difficulties in complying with AS 1215.16 with additional costs, while another firm indicated some technological and process challenges. Two commenters recommended making both due dates (*i.e.*, documentation completion date and Form AP due date) the same.

After considering the comments received, the Board adopted the accelerated documentation completion date of 14 days as proposed with modification to the effective date for certain firms discussed below. The 14-day timeline strikes a good balance of meeting the objectives of this amendment (*e.g.*, enhance investor protection by enabling the Board to begin the inspection process sooner after the completion of an audit) while still allowing a two-week period (14 calendar days) to assemble audit documentation for retention (*i.e.*, archive audit documentation). As echoed by some commenters, the Board believes that the accelerated documentation period will not require a

significant change for many firms. In the Board's view, the changes to the archiving period (*i.e.*, 14 days) are necessary to focus auditors on assembling a complete set of audit documentation that is high-quality and without documentation errors or omissions in a timely manner. The Board believes that a delay in assembling the audit documentation increases the potential for omissions to occur.

Further, shortening the archiving period also reduces the window of opportunity for improper alteration of audit documentation and increases the quality of documentation because recalling and describing audit procedures long after the work was actually performed can be difficult.

In accordance with AS 1215, the auditor must have completed all necessary auditing procedures and obtained sufficient evidence to support the representations in the auditor's report before the report release date.⁹⁴ The presence of complex financial accounting, reporting, or auditing matters should not have a bearing on the archiving period as the effects of such matters on the audit should be addressed before the report release date (*i.e.*, before the 14 days to assemble the audit documentation). Under existing AS 1215.16 auditors are allowed to add documentation after the documentation completion date, if needed.⁹⁵ While the Board understands that in practice some firms use a short archiving period, the Board believes that an archiving period of two days, as suggested by investor-related groups, may be too short to handle any unforeseen consequences (*e.g.*, technology interruptions) and could result in inadvertent non-compliance.

The Board also continues to believe that the accelerated documentation completion date of 14 days is still appropriate even when considering the Form AP deadline of 35 days. The Board acknowledged that in most situations, firms currently have 35 days to file Form AP,⁹⁶ and a firm must document the computation of total audit hours and include that computation in the files.⁹⁷ If the actual hours become available

after the documentation completion date but before the Form AP filing, the auditor is required under provisions of AS 1215 to add that information to the audit documentation after the documentation completion date.⁹⁸ The instructions to Form AP also provide that firms may use a reasonable method to estimate audit hours when actual hours have not been reported or are otherwise unavailable.⁹⁹

The Board acknowledged that certain firms may have less technologically advanced systems in place and may need more time to implement new processes to comply with the accelerated documentation completion date requirement. Therefore, as discussed in more detail below, the effective dates for this requirement allow a phased-in approach for smaller firms to comply with the 14-day documentation completion date. This approach addresses implementation challenges that some commenters suggested smaller firms may face.

ii. Specific Audit Documentation and Timing of Review

The Board also proposed to emphasize that audit documentation must clearly demonstrate who performed the work, who reviewed the work, and the date of such review.¹⁰⁰ In order for an engagement partner to conclude that the audit evidence obtained is sufficient and appropriate to support the opinion expressed in the auditor's report,¹⁰¹ the audit work is required to be reviewed prior to the report release date. Therefore, the Board also proposed to amend AS 1215.15 to clarify that, before the report release date, the engagement partner and other engagement team members performing supervisory activities have completed their reviews of audit documentation.

One commenter raised a concern that the amendments may result in lower quality documentation and an increase in late filings, providing an example of when a significant issue emerged closer to the issuer's filing deadline, because additional time to complete and review the relevant documentation would be needed. Another commenter suggested further clarifying whether the engagement partner and other supervisors must ensure that all review notes have been sufficiently addressed prior to the report release date.

The Board adopted the amendments to AS 1215 as proposed. The

⁹⁴ See AS 1215.15 (as amended).

⁹⁵ See AS 1215.16.

⁹⁶ Form AP has a filing deadline of 35 days after the date the auditor's report is first included in a document filed with the SEC, or 10 days after the auditor's report is first included in a document filed with the SEC for a registration statement under the Securities Act of 1933. PCAOB Rule 3211(b).

⁹⁷ See Improving the Transparency of Audits: Rules to Require Disclosure of Certain Audit Participants on a New PCAOB Form and Related Amendments to Auditing Standards, PCAOB Rel. No. 2015-008 (Dec. 15, 2015).

⁹⁸ See AS 1215.16.

⁹⁹ See Instructions to Form AP, Part IV—Responsibility for the Audit is Not Divided.

¹⁰⁰ See AS 1215.06.

¹⁰¹ See AS 2810.02.

requirement for the engagement partner and other supervisors to review relevant audit documentation prior to the report release date is a clarification of existing requirements in AS 1215 and AS 2101. As discussed earlier, since the auditor's report is dated no earlier than the date on which the auditor has obtained sufficient appropriate evidence to support the auditor's opinion,¹⁰² the auditor must have completed all necessary auditing procedures, including documentation to support the work performed that is reviewed by the engagement partner and other reviewers, on or before the auditor's report date, in all cases. The engagement partner and other supervisors should refer to existing requirements in AS 1215.07, in determining the sufficiency of audit documentation. Several factors to consider include nature of the audit procedure, risk of material misstatement associated with the assertion, and extent of judgment required in performing the work and evaluating the results (i.e., accounting estimates require greater judgment and commensurately more extensive documentation).¹⁰³

Lastly, in relation to proposed amendments in AS 1215.06 and .06A, one commenter agreed with the addition of paragraph .06A but suggested removing the phrase of "who performed the work, the person or persons who reviewed the work, and the date of such review" in AS 1215.06 because the same phrase is already included in AS 1215.06Ab. The Board did not make changes to the final amendments to AS 1215.06 and .06A. The addition of the phrase in paragraph .06 is an intentional clarification, rather than duplication, of what the audit documentation is required to demonstrate. The requirement in paragraph .06, is different, and relates to the sufficiency of documentation needed to meet the experienced auditor threshold.

The Board also proposed other amendments to AS 1215 to conform to AS 1000. These technical and clarifying amendments included replacing references to titles of existing standards with the title of the new standard and updating cross-referenced terminology and paragraph citations. The Board did not receive any comments relating to other amendments to AS 1215 and adopted those as proposed.

4. Other Amendments

In connection with the adoption of AS 1000, the Board also adopted other amendments to several PCAOB

standards to conform with AS 1000, amendments to AS 2810, and rescission of AS 2815. These amendments include superseding the foundational auditing standards.

The other changes adopted include replacing references to titles of existing standards with the title of the final standard and updating cross-referenced terminology and paragraph citations.

The proposed amendments that received comments are discussed in more detail below.

i. Amendments to AS 2710, Other Information in Documents Containing Audited Financial Statements

AS 2710.05 refers to differences in the auditor's judgment or opinion. The Board proposed to amend that standard in two ways, by clarifying that the difference of judgment or opinion is "between the auditor and the client," and by adding a footnote clarifying the meaning of "judgment." One commenter suggested replacing "the client" with "management" to be consistent with other PCAOB standards. Although the Board adopted other amendments that refer to the management and audit committee of the company under audit rather than to the auditor's "client," the Board did not make this change throughout the auditing standards because such a sweeping change is outside the scope of this project and may not be warranted in each instance, and thus could create confusion. Because "client" is used in AS 2710 throughout the standard, the Board retained the use of that term in the existing standard and in the amendment, and thus adopted the amendments to AS 2710.05 as proposed.

ii. Amendments to AS 3101, The Auditor's Report on an Audit of Financial Statements When the Auditor Expresses an Unqualified Opinion

The Board proposed to move certain language in paragraph .01 of AS 3101 to AS 1000. The Board also proposed to move footnote 2 that describes the term "taken as a whole" to paragraph .02 of AS 3101. Two commenters on the proposed amendments to AS 3101 suggested amending paragraph .11 and paragraph .14, primarily due to the declining number of CAMs disclosed by firms. Other commenters suggested adding language about the meaning of reasonable assurance means and the limitation of the audit in the auditor's report (paragraph .09 and Appendix B). The Board did not make these changes suggested by commenters because they are outside the scope of this project.

One commenter expressed concern that the meaning of "taken as a whole"

was changed because a footnote was added to AS 3101.02. As discussed above, the Board did not change the meaning of "taken as a whole" by moving the existing footnote to another paragraph. The Board therefore adopted the amendments as proposed.

iii. Amendments to AS 4105, Reviews of Interim Financial Information

The Board proposed to replace references to titles of existing standards with the title of the final standard and update cross-referenced terms and paragraph citations in paragraphs .01 and .07. Three commenters noted that the amendments are appropriate. One commenter suggested adding "to the extent those standards are relevant" in AS 4105.01 when referencing AS 1000 because interim reviews are not required to provide reasonable assurance. The Board believes this addition is not necessary because the amendment refers only to compliance with independence and ethics requirements, competence, and exercise of due professional care, which are fundamental to any audit, review, or attestation engagements under the PCAOB standards. All of these concepts are relevant to AS 4105 without exception. The Board adopted the amendments as proposed.

iv. Amendments to Attestation Standards

The Board proposed to replace references to titles of existing standards with the title of the final standard and update cross-referenced terms and paragraph citations. One commenter on these amendments stated that they are appropriate. Another commenter offered suggestions to (i) limit the references to AS 1000 in attestation standards because the general principles and responsibilities in AS 1000 should be specifically tailored to attestation engagements to be operable, (ii) retain paragraph .41 of AT Section 101, *Attest Engagements* a reference to *Cooley on Torts*, which was removed, and (iii) change the reference in footnote 9A of Attestation Standard No. 2, *Review Engagements Regarding Exemption Reports of Brokers and Dealers*, as "review" engagement as opposed to "examination" engagement. The Board noted that the references to AS 1000 have been tailored to the attestation standards. The Board did not retain the reference to the 1932 treatise *Cooley on Torts* because, as the Board explained when it proposed AS 1000, that reference is unnecessary and AS 1000 explains the concept of due professional care in plain language without changing

¹⁰² See paragraph .01 of AS 3110, Dating of the Independent Auditor's Report.

¹⁰³ See AS 1215.07.

its meaning.¹⁰⁴ The Board revised the footnote of AT No. 2 to refer to a “review” engagement. Otherwise, the Board adopted the amendments as proposed.

Effective Date

In the proposing release, the Board sought comment on the amount of time auditors would need before the proposed standard and related proposed amendments to PCAOB standards would become effective, if adopted by the Board and approved by the SEC. The Board proposed an effective date of June 30 of the year after approval by the SEC.

A number of commenters, mostly firms, suggested that an effective date be based on a fiscal year end date (e.g., audits of fiscal years ending on or after December 15) rather than the proposed effective date of June 30 in the year after SEC approval. These commenters generally pointed to challenges associated with a mid-year implementation (e.g., need to update firm methodologies for foundational standards and for performance standards amended by this project, provide training). Specific dates suggested by commenters included: (i) audits of periods beginning on or after December 15, 2024 (assuming 2023 SEC approval); (ii) 12 months after SEC approval; (iii) 18 months after SEC approval; and (iv) 24 months after SEC approval.

In addition, a firm and a firm-related group suggested that the Board consider the effective dates for other standard-setting projects such as QC 1000 when setting the effective date for AS 1000. In response to commenters, and after considering the effective dates for other Board rulemaking projects, the Board revised the effective date for the new standard and related amendments.

Subject to approval by the SEC, the new standard and related amendments will take effect for audits of financial statements for fiscal years beginning on or after December 15, 2024, except for the 14-day documentation completion date requirement (AS 1215.15). For that requirement, the Board adopted a phased approach to provide smaller firms more time to prepare for implementation. The requirement will take effect as follows:

- For public accounting firms that, during the calendar year ending December 31, 2024, issued audit reports with respect to more than 100 issuers, the 14-day documentation completion requirement will take effect for audits of financial statements for fiscal years

beginning on or after December 15, 2024; and

- For all other registered public accounting firms, the 14-day documentation completion requirement will take effect for audits of financial statements for fiscal years beginning on or after December 15, 2025.

The Board believes that changing the effective date to fiscal years beginning on or after December 15, 2024 responds to commenters who (i) expressed concerns about having a mid-year implementation and (ii) suggested that an effective date be based on a fiscal year-end date. Given the nature of requirements of the new standard and related amendments, as well as the extent of the differences between the new standard and the foundational standards, the Board believes that the general effective date will provide auditors with reasonable time to implement the new standard and related amendments. Further, extending the effective date for implementation of the 14-day documentation completion date requirement responds to the need articulated by commenters to provide smaller firms more time to prepare for implementation.

D. Economic Considerations and Application to Audits of Emerging Growth Companies

The Board is mindful of the economic impacts of its standard setting. This section describes the economic baseline, need, and expected economic impacts of the final standard and related amendments, as well as alternative approaches considered by the Board. Due to data limitations, the economic analysis is generally qualitative in nature.

The Board sought and received comments on the economic analysis in the proposing release.¹⁰⁵ A majority of the commenters expressed views related to the economic analysis, and they generally agreed with the need for the standard. Some commenters suggested that the use of certain proposed language or certain proposed clarifications could result in potential confusion or expansion of auditors’ responsibilities or that the proposed removal of certain extant explanatory language could reduce transparency regarding the meaning of the general principles and responsibilities and exacerbate an audit expectation gap. Some commenters suggested that the economic analysis should more carefully consider potential costs or unintended consequences associated with certain key provisions. These

comments are addressed below. One commenter asserted that costs that have not been analyzed, quantitatively or qualitatively, include costs to firms from new legal duties and auditor responsibilities. The commenters did not provide data to support their concerns about potential costs and unintended consequences. Their views were based on interpretations that the Board’s proposal would make broader changes. However, the Board believes the economic analysis is appropriate and consistent with the limited scope of changes the rulemaking requires. Commenters generally agreed that accelerating the documentation completion date is feasible for firms and beneficial to investors, although some commenters noted potential costs or questioned the expected benefits. One commenter suggested potential unintended consequences associated with clarifying engagement partner responsibilities. Three commenters referenced additional academic research for the Board’s consideration. These comments are addressed below.

The Board considered all of the comments received and have developed an economic analysis below that includes these considerations and evaluates the expected benefits and costs of the final standard and related amendments, discusses potential unintended consequences, and facilitates comparison to alternative actions considered. Specific input is discussed where relevant in the analysis that follows.

A. Baseline

The discussion above describes important components of the baseline against which the economic impacts of the standard can be considered, including an overview of existing requirements. Below is the Board’s discussion of additional matters that informed its understanding of the baseline for each of the changes.

1. Modernization of the Foundational Standards

The discussion above provides an overview of existing requirements of the auditing standards that describe the general principles and responsibilities of the auditor in conducting an audit in accordance with the standards of the PCAOB (i.e., foundational standards). The general principles and responsibilities addressed by the foundational standards are described above and include reasonable assurance, due professional care, professional skepticism, independence, competence, and professional judgment.

¹⁰⁴ See PCAOB Rel. No. 2023–001, at 22.

¹⁰⁵ See *id.* at 55–57.

The foundational standards are required to be followed in every audit conducted in accordance with PCAOB standards. The general principles and responsibilities in the foundational standards are reflected in firm methodologies, commercially published guidance, and other technical tools. Although there may be circumstances where some auditors' understanding of the general principles and responsibilities is made more difficult than necessary by how the foundational standards are organized and written, the Board does not have evidence that auditors are systematically confused about the meaning of the general principles and responsibilities or that the foundational standards are insufficient to support high-quality audits, when applied appropriately.

One commenter suggested there is no evidence that audit personnel are unclear or uncertain about the meaning of the proposed requirements. An investor-related group noted that the proposed standard was consistent with the extant standards.

The views expressed by the commenters align with the Board's belief that the core general principles and responsibilities encompassed by the foundational standards are well-established and sound. While the foundational standards are currently spread across four standards (*i.e.*, AS 1001, AS 1005, AS 1010, AS 1015), contain some extraneous restrictive language, and do not emphasize the investor protection obligation as prominently as desired, applied appropriately, they are sufficient to support high-quality audits.

2. Clarification of Engagement Partner Responsibilities

Under PCAOB standards, engagement partners are responsible for the engagement and its performance, including the proper planning and supervision of the engagement and its compliance with PCAOB standards. While engagement partners are permitted to seek assistance from other team members performing supervisory activities, engagement partners are responsible for proper supervision of the engagement and have primary responsibility for the engagement.

As discussed in the proposal, the staff reviewed firms' available methodology documentation to obtain an understanding of firms' policies and practices for engagement partner review.¹⁰⁶ A number of larger firms have developed specific guidance, checklists, and other tools to facilitate

the engagement partner's review. For example, some firms mandate the use of tools that specify workpapers or topics that engagement partners are required to review directly. These tools require the engagement partner to document their review. Conversely, similar policies of some smaller firms are designed to be applied at a higher level and are not as specific about the required review.¹⁰⁷ The Board did not receive comments that provided additional information addressing the baseline for engagement partner review.

3. Accelerating the Documentation Completion Date

The auditor is required to complete all necessary auditing procedures, review those procedures, and obtain sufficient appropriate audit evidence prior to the report release date. Auditors may need some time after the report release date to assemble the final audit file and complete the audit documentation. The PCAOB standard on audit documentation currently requires completion of documentation within 45 days after the report release date.

When PCAOB inspection staff select issuer audits for inspection, PCAOB notice of inspection and access to firm audit documentation generally do not occur until after the documentation completion date. After an inspection is complete, the Board issues a report on the inspection, and a portion of each report is made available to investors and the public on the PCAOB's website.

As discussed in the proposal, the staff reviewed firms' stated archiving policies and firms' archiving practices to obtain an understanding of firms' policies and practices for completing audit documentation.¹⁰⁸ The Board found a wide range of archiving periods among firms, from the full 45-day period to a much shorter period. In addition, PCAOB staff has observed that certain firms require audit documentation to be archive-ready upon completion of interim audit procedures. The PCAOB established the 45-day period in 2004¹⁰⁹ when firms relied more on

paper documentation and needed time to copy, collate, finalize, and file workpapers. PCAOB staff has observed that most firms today have electronic audit tools and audit software that either make those tasks unnecessary or enable the tasks to be performed much faster.

Some U.S. GNFs require engagement teams to archive audit documentation within 10 days after the report release date. Other firms require engagement teams to archive audit documentation within longer periods (ranging from 30 to 45 days after the report release date). Of the firms with policies that allow longer periods, certain of them express expectations to complete documentation within a much shorter period.

All GNFs have established global policies for archiving to be used by their respective non-U.S. affiliate firms. The global policies generally allow for completion of documentation not more than 45 days after the report release date. The global policies of certain GNFs specify a documentation completion date within 14 days after the report release date, or sooner when required by local laws or regulations. In addition to the global policies, certain non-U.S. affiliates of GNFs have local policies requiring documentation completion dates earlier than their respective global policies. Examples observed through the PCAOB's 2022 inspections include non-U.S. affiliates that have local policies specifying completion of documentation by deadlines such as 2 days, 7 days, 10 days, 14 days, and 30 days after the report release date. Additionally, even among certain non-U.S. affiliates that have stated policies of 45 days after the report release date, their documentation systems require completion of documentation within 15 to 40 days (depending on the firm). Generally, non-U.S. affiliates of GNFs use electronic audit documentation systems for documentation and archiving.

The archiving policies of NAFs generally specify a documentation completion date of 45 days after the report release date. PCAOB staff has observed certain NAFs annually inspected by the PCAOB that, in practice, typically archive documentation within 40 days of the report release date. In addition, PCAOB staff has noted that certain other NAFs generally complete their documentation at the end of the full 45-day archiving period. While most NAFs use electronic audit documentation systems, PCAOB staff is aware that some smaller firms still use paper-based workpapers.

The Board did not receive comments specific to the baseline for the documentation completion date,

¹⁰⁷ The observations in this paragraph are based on the staff's review of the policies of U.S. global network firms ("GNFs") and U.S. non-affiliate firms ("NAFs"). GNFs are the member firms of the six global accounting firm networks (BDO International Ltd., Deloitte Touche Tohmatsu Ltd., Ernst & Young Global Ltd., Grant Thornton International Ltd., KPMG International Ltd., and PricewaterhouseCoopers International Ltd.). NAFs are both U.S. and non-U.S. accounting firms registered with the Board that are not GNFs. Some of the NAFs belong to international networks.

¹⁰⁸ See PCAOB Rel. No. 2023-001, at 37.

¹⁰⁹ See *Audit Documentation and Amendment to Interim Auditing Standards*, PCAOB Rel. No. 2004-006 (June 9, 2004), at 5.

¹⁰⁶ See *id.* at 36.

including additional information on firms' current archiving policies and practices.

B. Need

The changes introduced in the final standard are part of the Board's effort to continuously improve and update PCAOB standards. In practice, PCAOB standards are used by auditors, who are responsible for applying the general principles and responsibilities of the foundational standards. Investors and other stakeholders may also rely on the foundational standards (directly or indirectly) to establish expectations about auditor responsibilities.

1. Problem To Be Addressed

i. Modernization of the Foundational Standards

The Board identified three potential concerns about the foundational standards: (i) compliance with the standards; (ii) soundness of the general principles and responsibilities; and (iii) clarity of the standards. The next three subsections explain that the Board does not see a need to make changes to the standards based on compliance with the standards or soundness of the general principles and responsibilities, but does see a need to make changes to modernize and enhance the clarity of the foundational standards.

a. Compliance With the Foundational Standards

In some instances, auditors have not performed audits in compliance with the foundational standards. For example, for the years 2018–2022, the PCAOB issued almost two dozen enforcement orders that described the violation of at least one of the foundational standards. One commenter, an academic, noted research that suggests that audit failures often relate to basic areas of auditor responsibility, such as failure to gather sufficient appropriate audit evidence, failure to exercise due professional care, or insufficient professional skepticism.¹¹⁰ The commenter added that contributing factors to the noted failures appear to be auditor disincentives to be skeptical¹¹¹ or high

auditor workloads.¹¹² For example, research indicates that professional skepticism could be affected by priorities such as engagement budgets rather than investor protection.¹¹³ The commenter also suggested that persistent audit deficiencies, despite PCAOB inspection and enforcement efforts, highlight the importance of auditors' understanding of and compliance with foundational auditing principles.¹¹⁴ The views expressed by the commenter seem to align with the Board's understanding of auditors' adherence to the foundational standards and the Board's assessment of the need to modernize and clarify those standards, including a reaffirmation of the auditor's obligation to protect investors.

b. Soundness of the General Principles and Responsibilities

The foundational standards address the general principles and responsibilities of reasonable assurance, due professional care, professional skepticism, independence, competence, and professional judgment. These principles and responsibilities are interconnected. For example, due professional care requires the auditor to exercise professional skepticism, including a questioning mind and a critical assessment of audit evidence. Audit procedures performed with due professional care allow the auditor to obtain reasonable assurance about whether the financial statements are free of material misstatement. Reasonable assurance is achieved, in part, by the exercise of professional judgment, which involves the auditor making decisions based on applying relevant training, knowledge, and experience. There is ample published research that studies alternative versions of these general principles and responsibilities. Below is a summary of several papers that demonstrate an ongoing debate regarding alternatives.

As noted in the proposal,¹¹⁵ academic research regarding professional skepticism provides a model that

identifies two components—skeptical judgment and skeptical action—that are necessary for the effective exercise of professional skepticism.¹¹⁶ In a synthesis of literature on professional skepticism, researchers conclude that professional skepticism is foundational to the performance of a high-quality audit, and they note that academic research tends to focus on skeptical judgment while PCAOB inspections tend to focus on skeptical action.¹¹⁷ When accountability to regulators is an incentive based on principles, research suggests that auditors may exhibit more skeptical judgment.¹¹⁸ When accountability is based on a checklist mentality of following a set of strictly specific requirements, research suggests that auditors may engage in cognitive processing that reduces skeptical judgment.¹¹⁹ On the other hand, a principles-only approach to standards may provide insufficient guidance to support the exercise of judgment.¹²⁰ Overall, therefore, there is a spectrum of possible approaches to audit regulation that lies between excessively vague principles and excessively specific requirements. In practice, effective auditing standards may fit into the middle of that spectrum by emphasizing core principles while including some specific requirements to help support skeptical judgment and skeptical action.¹²¹ One commenter, an academic, noted that research on rules- versus principles-based requirements for independence and ethics suggests that a combination of rules and principles is

¹¹⁶ See Mark W. Nelson, *A Model and Literature Review of Professional Skepticism in Auditing*, 28 *Auditing: A Journal of Practice & Theory* 1, 5 (2009).

¹¹⁷ See R. Kathy Hurr, Helen Brown-Liburd, Christine E. Earley, and Ganesh Krishnamoorthy, *Research on Auditor Professional Skepticism: Literature Synthesis and Opportunities for Future Research*, 32 *Auditing: A Journal of Practice & Theory* 45, 47 (2013). According to the authors, "Skeptical judgment occurs when an auditor recognizes that a potential issue may exist and that more work or effort is necessary. Skeptical action occurs when an auditor changes his/her behavior based on the skeptical judgment. Both skeptical judgment and skeptical action are essential to the audit, with skeptical judgment being a necessary condition for skeptical action."

¹¹⁸ See Hurr, et al., *Research on Auditor* 62.

¹¹⁹ See M. David Piercey, *Documentation Requirements and Quantified versus Qualitative Audit Risk Assessments*, 30 *Auditing: A Journal of Practice & Theory* 223, 242–43 (2011).

¹²⁰ See, e.g., SEC, *Study Pursuant to Section 108(d) of the Sarbanes-Oxley Act of 2002 on the Adoption by the United States Financial Reporting System of a Principles-Based Accounting System* (July 25, 2003).

¹²¹ See, e.g., AS 1210, *Using the Work of an Auditor-Engaged Specialist*.

¹¹⁰ See, e.g., Mark S. Beasley, Joseph V. Carcello, Dana R. Hermanson, and Terry L. Neal, *An Analysis of Alleged Auditor Deficiencies in SEC Fraud Investigations: 1998–2010* (commissioned by Center for Audit Quality) (May 2013).

¹¹¹ See, e.g., Joseph F. Brazel, Scott B. Jackson, Tammie J. Schaefer, and Bryan W. Stewart, *The Outcome Effect and Professional Skepticism*, 91 *The Accounting Review* 1577 (2016) and Joseph F. Brazel, Christine Gimbar, Eldar M. Maksymov, and Tammie J. Schaefer, *The Outcome Effect and Professional Skepticism: A Replication and a Failed*

Attempt at Mitigation, 31 *Behavioral Research in Accounting* 135 (2019).

¹¹² See, e.g., Julie S. Persellin, Jaime J. Schmidt, Scott D. Vandervelde, and Michael S. Wilkins, *Auditor Perceptions of Audit Workloads, Audit Quality, and Job Satisfaction*, 33 *Accounting Horizons* 95 (2019).

¹¹³ See, e.g., Brazel et al., *The Outcome Effect and Professional Skepticism* and Brazel et al., *The Outcome Effect and Professional Skepticism: A Replication and a Failed Attempt at Mitigation*.

¹¹⁴ See, e.g., Ashna L. Prasad and John C. Webster, *What Are the Trends in PCAOB Inspections and the Reported Audit Deficiencies?* 37 *Journal of Accounting, Auditing & Finance* 523 (2022).

¹¹⁵ See PCAOB Rel. No. 2023–001, at 39.

likely to be the most effective approach.¹²²

One commenter referenced several academic papers and highlighted pragmatic challenges and costs auditors face when applying the concept of professional skepticism.¹²³ The commenter reported that past economic research finds violations of professional skepticism underlying audit deficiencies.¹²⁴ The commenter also reported that lack of professional skepticism by auditors regarding frauds of the early 2000s generated academic literature on models of professional skepticism,¹²⁵ a scale to measure professional skepticism traits,¹²⁶ and interventions designed to help increase professional skepticism.¹²⁷ Moreover, the commenter reported that an area of academic psychology research asserts that skeptical behavior is a personality trait that may require a counter-dispositional change in mindset.¹²⁸ (The Board noted that this research does not

specifically study professional skepticism as a general principle or responsibility in auditing.) In contrast, another commenter reported that academic research highlights the merits of focusing on both obtaining and evaluating information as a pragmatic approach in the exercise of professional skepticism.¹²⁹

These comments suggest that efforts by firms, such as training and on-the-job-coaching, may be needed regarding professional skepticism, but do not suggest that professional skepticism as a general principle and responsibility of auditors is flawed. In addition, the views shared by these commenters underscore the need for a well-defined standard that sets forth the requirements of due professional care and professional skepticism, which is discussed further below.

As noted in the proposal, research also offers insights on the appropriate and expected levels of assurance for investors and other users of financial statements.¹³⁰ One accounting firm referenced a literature review that notes the audit expectation gap has existed for many years and describes it as a phenomenon in which the expectations of beneficiaries of audited financial statements exceed what auditors can reasonably be expected to accomplish.¹³¹ Early research on the audit expectation gap concludes that the majority of investors prefer absolute assurance that financial statements are free of material misstatement, in contrast to the profession's standard that an audit should provide reasonable assurance.¹³² Similarly, a more recent multi-country study finds that survey respondents appear to expect much more than reasonable assurance from auditors in order to prevent fraud and company failure.¹³³

The Board believes this cross-section of research, either noted in the proposal or by commenters, aligns with the Board's decision to maintain the core general principles and responsibilities

of the foundational standards. The synthesis research supports professional skepticism as foundational to the performance of effective audits. Likewise, the research on audit assurance supports the principle of reasonable assurance as an appropriate level of assurance based on the underlying benefits and costs of an audit engagement.¹³⁴ As explained above, absolute assurance is not attainable because of the nature of audit evidence and the characteristics of fraud. As described above, AS 1000 clarifies the general principles and responsibilities without substantially modifying the general principles and responsibilities. Moreover, the Board does not anticipate that the final standard and related amendments will markedly influence the current audit expectation gap since the Board preserved the core concepts while making marginal adjustments to reaffirm the auditor's obligation to protect investors.

c. Clarity of the Foundational Standards

As discussed in the proposal, some current features of the foundational standards do not support the most efficient use of the standards.¹³⁵ The general principles and responsibilities are currently spread across four standards, which were not developed originally as a cohesive whole. Their current organization continues to reflect their origin as separate requirements that were not drafted to be read together. In addition, the foundational standards contain language that was used in the AICPA's former standards but is outdated and inconsistent for audits conducted today under the standards of the PCAOB. This could undermine users' understanding of the general responsibilities of the auditor for audits conducted in accordance with PCAOB standards. The foundational standards also do not conform to the structure of Board-issued standards, which may hinder an auditor's navigation of the requirements. Finally, the foundational standards do not reflect developments in the auditing environment since their adoption in 2003, including the PCAOB's adoption of standards and rules, such as standards on audit documentation and engagement supervision, and this lack of consistency or alignment may draw attention away from the general principles and responsibilities.

Overall, these current features of the foundational standards may reduce

¹²² See, e.g., Terri L. Herron and David L. Gilbertson, *Ethical Principles vs. Ethical Rules: The Moderating Effect of Moral Development on Audit Independence Judgments*, 14 Business Ethics Quarterly 499 (2004) and Bryan K. Church, J. Gregory Jenkins, and Jonathan D. Stanley, *Auditor Independence in the United States: Cornerstone of the Profession or Thorn in Our Side?* 32 Accounting Horizons 145 (2018).

¹²³ See, e.g., Brazel et al., *The Outcome Effect*; Ashleigh L. Bakke, Elizabeth N. Cowle, Stephen P. Rowe, and Michael S. Wilkins, *How Do Audit Firms Treat Partners Who Issue Adverse Internal Control Opinions?* Available at SSRN: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4383557 (2023); Richard C. Hatfield, Scott B. Jackson, and Scott D. Vandervelde, *The Effects of Prior Auditor Involvement and Client Pressure on Proposed Audit Adjustments*, 23 Behavioral Research in Accounting 117 (2011); and Sandra Waller Shelton, *The Effect of Experience on the Use of Irrelevant Evidence in Auditor Judgment*, 74 The Accounting Review 217 (1999).

¹²⁴ See, e.g., Mark S. Beasley, Joseph V. Carcello, and Dana R. Hermanson, *Top 10 Audit Deficiencies*, Journal of Accountancy 63 (2001).

¹²⁵ See, e.g., Mark W. Nelson, *A Model and Literature Review of Professional Skepticism in Auditing*, 28 Auditing: A Journal of Practice & Theory 1 (2009).

¹²⁶ See, e.g., R. Kathy Hurr, *Development of a Scale to Measure Professional Skepticism*, 29 Auditing: A Journal of Practice & Theory 149 (2010).

¹²⁷ See, e.g., Jessica Maree Cross, Robyn Moroney, and Soon-Yeow Phang, *Is it All in the Mind(Fulness)? An Exploratory Study Assessing the Impact of Mindfulness on Professional Skepticism*, 37 Accounting Horizons 25 (2023).

¹²⁸ See, e.g., Lewis R. Goldberg, *The Structure of Phenotypic Personality Traits*, 48 American Psychologist 26 (1993); Paul E. Bebbington, Orla McBride, Craig Steel, Elizabeth Kuipers, Mirjana Radovanovic, Traolach Brugha, Rachel Jenkins, Howard I. Meltzer, and Daniel Freeman, *The Structure of Paranoia in the General Population*, 202 The British Journal of Psychiatry 419 (2013); and Ryan Hamilton, Kathleen D. Vohs, Anne-Laure Sellier, and Tom Meyvis, *Being of Two Minds: Switching Mindsets Exhausts Self-Regulatory Resources*, 115 Organizational Behavior and Human Decision Processes 13 (2011).

¹²⁹ See, e.g., Jonathan H. Grenier, *Encouraging Professional Skepticism in the Industry Specialization Era*, 142 Journal of Business Ethics 241 (2017) and Noel Harding and Ken T. Trotman, *The Effect of Partner Communications of Fraud Likelihood and Skeptical Orientation on Auditors' Professional Skepticism*, 36 Auditing: A Journal of Practice & Theory 111 (2017).

¹³⁰ See PCAOB Rel. No. 2023-001, at 39.

¹³¹ See Reiner Quick, *The Audit Expectation Gap: A Review of the Academic Literature*, 94 Maandblad voor Accountancy en Bedrijfseconomie 5 (2020).

¹³² See, e.g., Marc J. Epstein and Marshall A. Geiger, *Investor Views of Audit Assurance: Recent Evidence of the Expectation Gap*, 177 Journal of Accountancy 60, 64 (1994).

¹³³ See Association of Chartered Certified Accountants, *Closing the Expectation Gap in Audit* (May 2019) ("ACCA Report").

¹³⁴ See, e.g., Ernest L. Hicks, *Materiality*, 2 Journal of Accounting Research 158 (1964).

¹³⁵ See PCAOB Rel. No. 2023-001, at 40.

efficient use of the standards by requiring more time and attention than necessary to read, understand, and apply the standards and may lead to inconsistent application, potential misinterpretation, and ineffective regulatory intervention. Clarity of auditing standards requires effective communication through features such as relevant language, consistency with Board-issued standards and rules, and well-organized presentation, which appear throughout PCAOB and SEC rulemaking initiatives.

Several firms and a firm-related group acknowledged that modernization efforts to streamline and clarify the foundational standards will enhance users' awareness and understanding of the auditor's responsibilities.

(1) Characteristics of Modernized Auditing Standards

Academic research identifies three characteristics of effective disclosure documents that align well with the features of modernized auditing standards: simplicity,¹³⁶ salience,¹³⁷ and standardization.¹³⁸ Simplicity can be achieved with an auditing standard that eliminates language that is outdated and inconsistent. Salience can be achieved with an auditing standard that emphasizes requirements while including explanations in the Board's release rather than the rule text and that incorporates the latest developments in the auditing environment, including the adoption of Board-issued standards and rules. Standardization can be achieved with an auditing standard that is well-organized, with general principles and responsibilities presented in a single standard that is structured similar to other standards.

In addition, the Board is aware of other regulatory initiatives that emphasize clear, well-organized writing as characteristics of effective communication with stakeholders. Two examples of other regulatory initiatives are the SEC Plain English Disclosure

rule¹³⁹ for issuers' prospectuses, and the Plain Writing Act of 2010¹⁴⁰ for government communications with the public. The purpose of the Plain English Disclosure rule was to make financial and business information available to investors in a form they could read and understand, and the rule includes specific guidance for clear, concise language.¹⁴¹ The purpose of the Plain Writing Act was to improve the effectiveness and accountability of federal agencies to the public by promoting clear communication that the public can understand and use, and the statute defines plain writing as writing that is clear, concise, and well-organized, and that follows other best practices appropriate to the subject and the intended audience.¹⁴² While neither the Plain English Disclosure rule nor the Plain Writing Act imposes obligations on the PCAOB, their overall objective to promote effective communication for efficiency of stakeholders' understanding is aligned with the objectives of and approach to the Board's modernization of the foundational standards.

The Board did not receive comments that provided additional information regarding characteristics of modernized auditing standards.

(2) Useability of Modernized Auditing Standards

As summarized above, the Board continues to believe that auditors generally understand their responsibilities under the foundational standards. Nonetheless, there could be certain circumstances where some auditors' understanding of the general principles and responsibilities is made

more difficult than necessary by the current language and organization of the foundational standards. New entrants, for example, may need to spend more time navigating and distilling the extant general principles and responsibilities than they would with more modernized language and organization. These new entrants may include accounting students seeking to enter the auditing profession. They may also include auditors who are experienced in applying other auditing or attestation standards, such as those of the AICPA for entities other than issuers, but who are seeking to perform an audit under PCAOB standards for the first time and who need to confirm their responsibilities under PCAOB rules.

In addition, the current language and organization of the foundational standards could impede investors' abilities to form accurate expectations about auditor responsibilities under PCAOB standards. Investors form expectations from a number of sources, including potentially the language of the standards themselves, but also from third parties (e.g., media) who may write about PCAOB standards. Standards that are not modernized could contribute to an expectation gap—in this case, a gap between what investors expect from an audit and what auditing standards require.¹⁴³ Such a gap could in principle exist in either direction. Investors could be led to expect more than what an audit is required to deliver, and thereby fail to price the risk appropriately. Alternatively, investors could be led to expect less than what an audit is required to deliver, and thereby fail to appreciate the important functions performed by auditors regarding reasonable assurance.

Audit committees may also form inaccurate expectations about the content of PCAOB standards if the standards are not modernized, via mechanisms similar to investors. Given audit committee members' greater familiarity with auditing through their position and responsibilities with the issuer and other relevant professional background, the Board believes this is

¹³⁶ See, e.g., R.E. Nisbett and L. Ross, *Human Inference: Strategies and Shortcomings of Social Judgment* (1980) (finding that individuals have limited cognitive resources to absorb and process information).

¹³⁷ See, e.g., Daniel Kahneman, *Thinking, Fast and Slow* (2013) (suggesting that individuals who focus their limited cognitive resources on a subset of information are able to give more weight to the subset when making decisions).

¹³⁸ See, e.g., Jeffrey R. Kling, Sendhil Mullainathan, Eldar Shafir, Lee C. Vermeulen, and Marian V. Wrobel, *Comparison Friction: Experimental Evidence from Medicare Drug Plans*, 127 *The Quarterly Journal of Economics* 199 (2012) (finding that standardized information better enables individuals to assess tradeoffs and make coherent, rational decisions).

¹³⁹ *Plain English Disclosure*, SEC Rel. No. 33–7497 (Oct. 1, 1998).

¹⁴⁰ *Plain Writing Act of 2010*, Public Law 111–274.

¹⁴¹ The economic effects of easy-to-read disclosure documents are quantified in research that demonstrates a decrease in company valuation caused by a decrease in readability of disclosure documents. See Byoung-Hyoun Hwang and Hugh Hokwang Kim, *It Pays to Write Well*, 124 *Journal of Financial Economics* 373 (2017).

¹⁴² Using the Plain Writing Act as an exogenous event, research has found that the Plain Writing Act resulted in improved readability of Form 10–Ks that caused the risk of stock price crash to fall. See Shiyang Yin, Thanaset Chevapatrakul, and Kai Yao, *The Causal Effect of Improved Readability of Financial Reporting on Stock Price Crash Risk: Evidence from the Plain Writing Act of 2010*, 216 *Economics Letters* (2022). Research has also found that while readability of disclosures improved following the Plain English Disclosure rule, improved readability does not appear to influence more experienced market participants, as measured by equity analysts' earnings forecasts. See Samuel B. Bonsall IV, Andrew J. Leone, Brian P. Miller, and Kristina Rennekamp, *A Plain English Measure of Financial Reporting Readability*, 63 *Journal of Accounting and Economics* 329 (2017).

¹⁴³ Research finds evidence of a persistent gap between investors' expectations of an audit and auditors' performance based on requirements under auditing standards. See, e.g., Klaus Ruhnke and Martin Schmidt, *The Audit Expectation Gap: Existence, Causes, and the Impact of Changes*, 44 *Accounting and Business Research* 572, 592 (2014) (finding that the public has expectations of auditors' responsibilities that do not exist under auditing standards, such as conducting a management audit) and ACCA Report (finding that the persistence of the audit expectation gap reflects, in part, the fact that public expectations of audits can grow in line with what auditors can accomplish).

less likely to occur for audit committees than for investors. However, the negative impact of an audit committee member failing to correctly comprehend the auditor's general responsibilities under PCAOB standards could be more severe, given the audit committee's role in supervising the audit and the auditor under Sarbanes-Oxley for the benefit of investors.

The Board did not receive comments that provided additional information regarding useability of modernized auditing standards.

ii. Clarification of Engagement Partner Responsibilities

One of the responsibilities of engagement partners is to review the work of engagement team members. Any uncertainty under the standards may give engagement partners an incentive, particularly under time pressures, to de-emphasize or omit the review of workpapers. For example, the Board has found instances in which engagement partners did not fulfill their responsibilities for review.¹⁴⁴ However, engagement partner review of workpapers is a critical step to promote audit quality. As noted above, firms have varying policies and tools to facilitate the review required by the engagement partner.

One commenter, an academic, referenced academic studies regarding engagement partner impacts. The commenter reported that one study using data from Taiwan finds evidence that suggests there is variation in the quality of engagement partners and that the market responds to engagement partner quality.¹⁴⁵ In addition, the commenter reported that a group of studies finds evidence that engagement partners can negatively impact audit quality when they do not follow auditing standards, such as by not promoting the need for professional skepticism, ethical behavior, and continuing education.¹⁴⁶ The views

shared by the commenter align with the Board's identification of the need to clarify the engagement partner's responsibility to review certain audit documentation.

iii. Accelerating the Documentation Completion Date

The discussion above emphasizes the importance of adequate audit documentation and the auditor's responsibilities for documentation under AS 1215, which currently specifies an audit documentation completion date no more than 45 days after the report release date. PCAOB standards require auditors to complete all necessary auditing procedures, review those procedures, and obtain sufficient appropriate audit evidence prior to the report release date. The extant requirements were established in part because documentation that is added well after the completion of an audit is likely to be of lesser quality than documentation produced contemporaneously when audit procedures are performed because reconstructing and recalling activities related to performing audit procedures long after the work was actually performed can be difficult.¹⁴⁷

Separately, significant advancements in electronic audit tools and the use of audit software have occurred over the last two decades, which facilitate contemporaneous documentation and more timely documentation completion. Based on these observations and some firms' policies and practices summarized above, the current documentation completion date that is 45 days after the report release date may provide more time than necessary to complete and finalize the audit documentation.

The PCAOB inspection process generally cannot begin until after the documentation completion date. In cases where the PCAOB would like to initiate inspections earlier, the 45-day period imposes an unnecessarily long lag before the PCAOB can provide notice of inspection and obtain access to audit documentation, which may prevent timely identification and resolution of audit deficiencies and delay information on firm performance that is useful to investors for assessing attributes such as audit quality or auditor effort.¹⁴⁸

and Client Pressure on Auditors' Judgments, 93 The Accounting Review 335 (2018).

¹⁴⁷ See PCAOB Rel. No. 2004–006.

¹⁴⁸ See, e.g., Jagan Krishnan, Jayanthi Krishnan, and Hakjoon Song, *PCAOB International Inspections and Audit Quality*, 92 The Accounting Review 143 (2017) (finding evidence consistent with improvements in audit quality for foreign

As discussed in the Board's proposal, the 45-day period also may pose a greater risk of improper alteration of audit documentation because it provides a lengthy window of opportunity between the release of the audit report and the completion of the audit documentation.¹⁴⁹

The Board did not receive comments that provided additional information regarding the need to accelerate the documentation completion date.

2. How the Changes Address the Need

i. Modernization of the Foundational Standards

The changes modernize the foundational standards by reorganizing and consolidating four standards, eliminating language that is no longer relevant, establishing conformity with the structure of Board-issued standards, and harmonizing with PCAOB standards and rules issued after the adoption of interim standards in 2003. These changes are designed to make AS 1000 a more effective and efficiently used standard through a well-organized presentation with relevant language that is more consistent with other PCAOB standards.

ii. Clarification of Engagement Partner Responsibilities

The changes clarify engagement partner responsibilities by specifying the engagement partner's due professional care responsibilities, explicitly stating that the engagement partner has primary responsibility for the engagement that is not reduced when assistance is provided by other engagement team members, and explicitly stating that audit documentation must clearly demonstrate the person or persons who reviewed the work and the date of such review. Clarification of the engagement partner's responsibility to review certain audit documentation—including review of documentation of significant findings or issues and review of documentation that is required to be reviewed by the EQR—reaffirms the existing minimum level of responsibilities under due

firms after PCAOB inspections) and Daniel Aobdia, *The Impact of the PCAOB Individual Engagement Inspection Process—Preliminary Evidence*, 93 The Accounting Review 53 (2018) (finding increases in auditor effort subsequent to deficiencies found through PCAOB inspections). The Board notes that the results from these studies do not necessarily mean that PCAOB inspections cause higher audit quality.

¹⁴⁹ For examples of improper alteration of audit documentation within the 45-day archiving period, see, e.g., *In the Matter of Deloitte LLP*, PCAOB Rel. No. 105–2021–014 (Sept. 29, 2021) and *In the Matter of Richard J. Bertuglia, CPA*, SEC Rel. No. 84419 (Oct. 12, 2018).

¹⁴⁴ See, e.g., *In the Matter of Jin Tae Kim*, PCAOB Rel. No. 105–2022–013 (Aug. 16, 2022) and *In the Matter of KPMG Assurance and Consulting Services LLP and Sagar Pravin Lakhani*, PCAOB Rel. No. 105–2022–033 (Dec. 6, 2022).

¹⁴⁵ See, e.g., Daniel Aobdia, Chan-Jane Lin, and Reining Petacchi, *Capital Market Consequences of Audit Partner Quality*, 90 The Accounting Review 2143 (2015).

¹⁴⁶ See, e.g., Sean A. Dennis and Karla M. Johnstone, *A Field Survey of Contemporary Brainstorming Practices*, 30 Accounting Horizons 449 (2016); Harding and Trotman, *The Effect of Partner 111*; Christopher Koch and Steven E. Salterio, *The Effects of Auditor Affinity for Client and Perceived Client Pressure on Auditor Proposed Adjustments*, 92 The Accounting Review 117 (2017); and William F. Messier, Jr. and Martin Schmidt, *Offsetting Misstatements: The Effect of Misstatement Distribution, Quantitative Materiality,*

professional care and promotes consistency across audits regarding an engagement partner's oversight of the audit.

iii. Accelerating the Documentation Completion Date

The changes accelerate the documentation completion date by reducing the maximum period for the auditor to assemble a complete and final set of audit documentation from 45 days to 14 days after the report release date. This change enables PCAOB inspections staff earlier access to audit documentation and reduces the window of opportunity for improper alteration of audit documentation prior to the documentation completion date.

C. Economic Impacts

This section discusses the expected benefits and costs of the changes and potential unintended consequences. The proposal described expected benefits and costs, resulting in comments on each.¹⁵⁰ Two commenters on the proposal noted that the changes will not result in any significant additional costs to auditors or the companies they audit or in any significant benefits to market participants. Some commenters suggested that the economic analysis should more carefully consider potential costs or unintended consequences associated with certain key provisions, as discussed further below. The Board expects the economic impacts of AS 1000, including both benefits and costs, to be relatively modest, especially for those firms that have already incorporated in practice an engagement partner's responsibility for review and an accelerated documentation completion date.

1. Benefits

i. Modernization of the Foundational Standards

To the extent that current features of the existing foundational standards reduce efficient use of the standards, the changes will help enhance useability by making the general principles and responsibilities of the auditor in conducting an audit in accordance with the standards of the PCAOB easier to read, understand, and apply in practice.

For users trying to navigate and understand the general principles and responsibilities, efficiency gains may be associated with each of the changes as follows:

- The change to reorganize and consolidate the standards into a single standard will reduce time and attention required to navigate several standards to

locate the general principles and ensure relevant requirements are met.

- The changes to eliminate language that is no longer relevant will reduce time and attention required to read, understand, and apply the standard by facilitating a focus on core requirements of the standard.

- The changes to establish conformity with the structure of Board-issued standards and make certain enhancements will help expedite navigation of the requirements and ensure relevant requirements are met by: (i) providing more uniformity among the PCAOB standards with an introduction and objectives that emphasize the auditor's obligations; (ii) updating the articulations of the concepts of due professional care, professional skepticism, professional judgment, and reasonable assurance; (iii) clarifying auditor responsibilities by expressing the requirements using Rule 3101 terms; and (iv) minimizing explanatory material that is instead included in the release discussion.

- The changes to harmonize with PCAOB standards and rules issued after adoption of the interim standards in 2003 will reduce time and attention required to read, understand, and apply the standard by drawing attention to: (i) changes to auditing requirements through Board-issued standards; (ii) clarifying the meaning of present fairly; (iii) an overarching objective for audits of ICFR; and (iv) new rules issued by the Board.

Auditors learning the general principles and responsibilities for the first time may do so more quickly and easily, thereby reducing the cost of training and potentially facilitating the newer auditor's ability to perform PCAOB audits.

While the obligation of auditors would not change, reaffirming the auditor's obligation to protect investors could serve as a reminder. Especially to the extent that auditors do not currently fulfill this obligation, it may prompt auditors to reflect on a sense of obligation to investors and the public that goes beyond their responsibilities to a specific company under audit. At the margins, the emphasis on investor protection could reinforce support for auditors in circumstances where they face decisions that may require them to prioritize the interests of the public over their own interests or the interests of the company under audit. Further, by highlighting the important role auditors play in protecting investors, it could underscore the value of the auditing profession to capital markets.

In addition, a modernized standard may enhance investors' and audit

committees' awareness and understanding of the auditor's responsibilities. Investors could be able to more appropriately assess financial statement risk by better understanding the nature and extent of auditor responsibilities. Audit committees' oversight of the auditor could be enhanced, for example, if enhanced clarity of standards facilitates communication between the audit committee and the auditor. Referencing academic research, one commenter on the proposal explained that the role of the audit committee in ensuring the quality of reported financial results requires improved and expanded dialogue between the audit committee and the auditor.¹⁵¹

ii. Clarification of Engagement Partner Responsibilities

To the extent that engagement partners currently do not fulfill their responsibilities for an appropriate review of the work of other engagement team members as required under the existing standards,¹⁵² the clarification of engagement partner responsibilities could improve auditor performance and audit quality by: (i) improving the timeliness of the engagement partner's evaluation of significant findings and judgments; (ii) enhancing the ability of the engagement partner to prevent or detect audit deficiencies; and (iii) facilitating improvements in the quality of the work of other engagement team members. As summarized above, one commenter referenced academic studies that suggest engagement partners can negatively impact audit quality when they do not follow auditing standards.

iii. Accelerating the Documentation Completion Date

The amendment to accelerate the documentation completion date by reducing the maximum period for the auditor to assemble a complete and final set of audit documentation from 45 days to 14 days after the report release date will promote contemporaneous documentation and more timely documentation completion. Documentation that is produced contemporaneously when audit procedures are performed and then completed soon thereafter is likely to provide a more accurate and complete

¹⁵¹ See, e.g., Jeffrey Cohen, Lisa Milici Gaynor, Ganesh Krishnamoorthy, and Arnold M. Wright, *Auditor Communications with the Audit Committee and the Board of Directors: Policy Recommendations and Opportunities for Future Research*, 21 Accounting Horizons 165 (2007).

¹⁵² See, e.g., Jin Tae Kim, PCAOB Rel. No. 105–2022–013 and KPMG Assurance and Consulting Services LLP, PCAOB Rel. No. 105–2022–033.

¹⁵⁰ See PCAOB Rel. No. 2023–001, at 45–50.

audit file for the engagement. The amendment will also support PCAOB efforts to enhance audit quality via timelier identification and potential resolution of audit deficiencies in cases where inspections are initiated earlier. In such cases, the amendment could facilitate earlier issuance of inspection reports and their availability to investors. In addition, the amendment could enhance auditor performance and audit quality for firms that do not currently implement best practices, but will be more inclined to do so, by proactively focusing on sequencing of work, allocation of resources, and other operating practices.

The benefits associated with an accelerated documentation completion date are likely to be greater for firms that currently make use of the entire 45-day period permitted under current PCAOB standards due to current operating circumstances. These firms would need to make more adjustments to their sequencing of work and allocation of effort to meet the accelerated period. Thus, the concomitant benefits to audit quality would therefore be greater. Based on firms' current archiving policies and practices summarized above, the benefits associated with an accelerated documentation completion date are likely to be higher for NAFs than for GNFs in cases where NAFs experience operating efficiencies associated with changes in their sequencing of work, allocation of resources, and other operating practices to comply with the documentation completion date.

The benefits associated with an accelerated documentation completion date will be lower for firms that already either: (i) have a policy that requires that documentation be completed in 14 days or fewer or (ii) have a policy that is closer to or equal to the current 45-day period but in practice complete their documentation shortly after releasing the audit report. Specifically, the benefits to audit quality will be lower for these firms, but the benefits to investors of earlier PCAOB inspections will still be achieved in cases where inspections are initiated earlier.

Commenters on the proposal generally agreed that accelerating the documentation completion date is feasible for firms and beneficial to investors. One commenter suggested the ability to inspect audits sooner is a benefit that will not significantly increase costs. Another commenter, an academic, suggested there could be market benefits associated with earlier inspections if inspection reports are publicly available earlier and the content of inspection reports is

meaningful. The commenter referenced several academic studies that demonstrate improvements in audit quality after PCAOB inspections.¹⁵³ The commenter reported that one study finds improvements in internal control audits after PCAOB inspections¹⁵⁴ and that another study finds increases in auditor effort after PCAOB inspections find audit deficiencies.¹⁵⁵ One commenter questioned whether accelerating the documentation completion date would have any meaningful impact on inspection timelines. Based on the acceleration of the documentation completion date by 31 days, the Board noted that the most an inspection report could be accelerated as a result of the accelerated documentation completion date is 31 days.

2. Costs

i. Modernization of the Foundational Standards

The primary costs of the modernization efforts reflected in the standard will be one-time costs to firms for updating references within firm methodologies and related guidance to reflect the final standard and related amendments. Larger firms that develop their own methodologies will update references directly in those methodologies. Smaller firms generally purchase methodologies from third-party vendors. The implementation costs of the changes may be offset over time because a more logical and easy-to-read-and-navigate standard could enable auditors to save time reading, understanding, and applying the standard. Third parties that refer to PCAOB standards (e.g., in textbooks, training, or review materials) will also need to update those materials.

To the extent that auditors are not taking into account PCAOB auditing interpretations, as used in paragraph .15 and the related note of the standard, those firms will also incur one-time and ongoing costs related to methodology and periodic training for PCAOB auditing interpretations.

To the extent that auditors do not currently fulfill their obligation to protect investors, auditors who face decisions that require them to prioritize the interests of the public over their own interests or the interests of the

company under audit may make decisions that benefit the public at a potential cost to the auditor, such as alienating or losing a company under audit. There is likely already a balance struck between fulfilling the auditor's obligation to protect investors and the risk of alienating or losing a company under audit. At the margins, the emphasis on investor protection may move the fulcrum closer to the public interest.

The Board did not receive comments that provided additional information regarding costs of modernization.

ii. Clarification of Engagement Partner Responsibilities

To the extent that engagement partners currently do not fulfill their responsibilities for an appropriate review of the work of other engagement team members as required under the existing standards,¹⁵⁶ those firms may incur one-time costs to update firm methodologies and ongoing costs related to fulfilling their responsibilities. Larger firms that develop their own methodologies will update references directly in those methodologies. Smaller firms generally purchase methodologies from third-party vendors.

While the responsibilities of engagement partners would not change under the new standard, the clarification for engagement partners to perform their duties with due professional care, including their responsibility for performing an appropriate review of the work of other engagement team members, could also impose incremental costs related to fulfilling engagement partner responsibilities to the extent that engagement partners are not currently fulfilling their responsibilities.

One commenter reported that research highlights the importance of and variation in the direction, supervision, and review of audit work.¹⁵⁷ The commenter further noted that direction, supervision, and review are functions that are performed by auditors at different levels of experience, not just engagement partners, and cited research that highlights that the effectiveness of the functions can vary across

¹⁵⁶ See, e.g., Jin Tae Kim, PCAOB Rel. No. 105–2022–013 and KPMG Assurance and Consulting Services LLP, PCAOB Rel. No. 105–2022–033.

¹⁵⁷ See, e.g., J.S. Rich, I. Solomon, and K.T. Trotman, *The Audit Review Process: A Characterization from the Persuasion Perspective*, 22 Accounting, Organizations & Society 481 (1997) and Mark Nelson and Hun-Tong Tan, *Judgment and Decision Making Research in Auditing: A Task, Person, and Interpersonal Interaction Perspective*, 24 Auditing: A Journal of Practice & Theory 41 (2005).

¹⁵³ See, e.g., Krishnan, et al., *PCAOB International Inspections*. The Board notes that the results from these studies do not necessarily mean that PCAOB inspections cause higher audit quality.

¹⁵⁴ See, e.g., Mark L. DeFond and Clive S. Lennox, *Do PCAOB Inspections Improve the Quality of Internal Control Audits?* 55 Journal of Accounting Research 591 (2017).

¹⁵⁵ See, e.g., Aobdia, *The Impact of the PCAOB*.

hierarchical levels.¹⁵⁸ While the Board acknowledged the commenter's points regarding the effectiveness of functions performed by auditors at different levels of experience, the Board's analysis of costs here is limited to costs that are relevant to the economic impacts of the clarification of engagement partner responsibilities.

iii. Accelerating the Documentation Completion Date

The amendment to accelerate the documentation completion date by reducing the maximum period for the auditor to assemble a complete and final set of audit documentation from 45 days to 14 days after the report release date will allow less time to assemble the final set of workpapers after the audit report is released. However, the PCAOB requirement to complete necessary auditing procedures, review those procedures, and collect sufficient appropriate audit evidence prior to the report release date could help mitigate costs to implement the amendment because the only activities that remain are assembling a complete and final set of audit documentation. In addition, the widespread use of electronic audit tools and audit software could help mitigate any costs associated with the amendment.

The costs associated with an accelerated documentation completion date are likely to be greater for firms that currently specify by policy an archiving period that is near or equal to the maximum permitted under current AS 1215.15 and that currently take all or nearly all of the full 45-day period to complete their archiving because of operating circumstances that inhibit faster completion. These firms will have to invest additional resources to enhance sequencing of their work, allocation of resources, and other operating practices, or may have to enhance their audit documentation systems, or both, in order to comply with the documentation completion date. Based on firms' current archiving policies and practices summarized above, the costs associated with an accelerated documentation completion date are likely to be higher for NAFs than for GNFs in cases where NAFs currently use the entire 45-day period. However, the extended effective date of the 14-day requirement for firms that issued audit reports with respect to 100

or fewer issuers during the calendar year ending December 31, 2024, will allow those firms more time to implement the revised requirement. By contrast, GNFs that already require the completion of documentation within a 14-day period will likely not incur substantial additional costs to comply with the revised requirement.

Electronic audit tools and audit software may facilitate compliance with the requirement by automating, and thereby performing more quickly, certain processes. For firms without electronic systems in place, costs associated with an accelerated documentation completion date may include additional resources, such as in-house personnel or capital investments in audit software, to help assemble a complete and final set of audit documentation in the 14-day time period. PCAOB staff is aware that some small NAFs still use paper-based systems. However, these firms generally perform smaller, less complex audits, such that the firms do not have to mail audit workpapers from multiple locations; therefore, even with a paper-based system, effective sequencing of work, allocation of resources, and other operating practices could enable them to meet the 14-day documentation completion date.

For firms with electronic audit tools and audit software in place, the earlier documentation completion date should not change the functionality or cost of software, which will facilitate a low-cost transition to the new archiving period. Some firms already have policies that require documentation completion within 14 days of the report release date, and some firms require audit documentation to be archive-ready upon completion of interim procedures. These practices suggest that much of the process involved in assembling a complete and final set of audit documentation, such as assembly, cleanup, and retention, is substantially finished in advance of 45 days. Any firms that currently have a policy or practice of completing audit documentation on or near the 45th day may do so merely because the current standard allows 45 days, and thus will not incur costs to meet the accelerated documentation completion date. Alternatively, any firms that currently complete audit documentation on or near the 45th day because of operating circumstances may incur costs associated with implementing best practices to effectively sequence work, allocate resources, and incorporate other operating practices to comply with the accelerated documentation completion date. In this case, the Board anticipates

that the costs will be offset over time by improvements in operating efficiencies to the extent that operating circumstances are within the firm's control.

An accelerated documentation completion date may also impose costs on multi-firm audits if electronic audit documentation systems are not integrated across firms. GNFs are more likely than NAFs to perform multi-firm audits, but some NAFs do perform multi-firm audits.¹⁵⁹ If electronic systems are not integrated across firms, which is more likely for NAFs, other auditors may need to transmit documentation to the lead auditor to assemble the final set of workpapers. If electronic systems are integrated across firms, the lead auditor may be able to seamlessly archive the work of other auditors.

Any costs associated with the requirements may be passed through to investors, or costs may be internalized by firms. While competition in the audit market is characterized by a combination of unique features,¹⁶⁰ issuers that engage firms that pass through any costs may switch firms if the benefits of switching justify the costs of switching.

Some commenters noted potential costs associated with accelerating the documentation completion date. One commenter generally supported accelerating the documentation completion date but noted that firms that use proprietary audit tools and audit software will incur costs related to reprogramming and testing that could be exacerbated for GNFs that are subject to differing jurisdictional requirements. The same commenter also noted that accelerating the documentation completion date may negatively impact smaller firms that do not utilize electronic audit tools to the extent that they are unable to comply with the requirement without considerable investments that may not be economically feasible. Another commenter disagreed with accelerating the date because of human capital factors and a complex auditing landscape. Another commenter reported that academic research investigating the SEC's acceleration of Form 10-K filing deadlines in the 2000s suggests that accelerating the filing deadlines more

¹⁵⁹ See PCAOB Rel. No. 2022-002, at 26-52.

¹⁶⁰ See, e.g., Joseph Gerakos and Chad Syverson, *Competition in the Audit Market: Policy Implications*, 53 *Journal of Accounting Research* 725 (2015) (explaining that the audit market exhibits a set of features that distinguish it from other markets for business services, including its role in capital market transparency, mandated demand, and concentrated supply).

¹⁵⁸ See, e.g., Robert J. Ramsay, *Senior/Manager Differences in Audit Workpaper Review Performance*, 32 *Journal of Accounting Research* 127 (1994) and Noel Harding and Ken T. Trotman, *Hierarchical Differences in Audit Workpaper Review Performance*, 16 *Contemporary Accounting Research* 671 (1999).

quickly than 15 days was costly to issuers regarding misstated financial statements.¹⁶¹ The commenter acknowledged the analogy may not align with the documentation completion date but suggested that it is likely that firms currently requiring more than 29 days to complete audit documentation will likely incur non-trivial compliance costs.

The Board acknowledged that firms that use proprietary audit tools and audit software will incur costs related to reprogramming and testing. While the Board also acknowledged that some smaller firms may incur costs related to investments and some firms may incur costs related to human capital or a complex auditing landscape, the Board believes that most firms will incur incremental costs because they already use electronic audit documentation systems. Likewise, the Board believes the contrast between the SEC's acceleration of Form 10-K reporting deadlines and the Board's acceleration of the documentation completion date is too stark to be a useful comparison because the auditing standards require that all necessary auditing procedures, review of those procedures, and collection of sufficient appropriate audit evidence be completed prior to the report release date. Based on the broad support by commenters for accelerating the documentation completion date and the existing requirement that all necessary auditing procedures, review of those procedures, and collection of sufficient appropriate audit evidence be completed prior to the report release date, the Board continues to believe that accelerating the documentation completion date by reducing the maximum period for the auditor to assemble a complete and final set of audit documentation from 45 days to 14 days after the report release date will provide better protection for investors.

One commenter suggested that keeping the 35-day filing requirement for Form AP in light of accelerating the documentation completion date could create technological and process challenges for firms. Another commenter suggested that firms could incur incremental costs such as process

changes and administrative costs. In contrast, some commenters said they would not have difficulty filing Form AP within 35 days of the audit report being filed with the SEC. Two commenters suggested the time to file Form AP should be consistent with the documentation completion date. The Board adopted the 14-day deadline for archiving audit documentation. The Board noted that firms, under AS 1215, can add information to the audit documentation after the documentation completion date, if necessary, to record their compliance with Form AP requirements. Consequently, the Board does not perceive any conflict or a necessity to modify either the 35-day Form AP filing requirement or the proposed 14-day deadline for archiving audit documentation.

3. Potential Unintended Consequences

In addition to the benefits and costs discussed above, the final standard and related amendments could have unintended economic consequences. The proposal described potential unintended consequences, which commenters addressed in their letters.¹⁶² This section discusses the potential unintended consequences the Board considered as well as its consideration of such consequences in adopting the final standard and related amendments. The discussion also addresses, where applicable, any mitigating or countervailing factors, including revisions to the proposed standard and related amendments reflected in the final standard and related amendments the Board adopted.

i. Modernization of the Foundational Standards

The changes to modernize the foundational standards are not intended to impose new requirements on auditors or substantially change the requirements of PCAOB standards.

Commenters noted potential unintended consequences related to the removal of explanatory language or the use of certain language in the proposed rule text or release discussion. Several commenters suggested that removing explanatory language on limitations of an audit may exacerbate the audit expectation gap and cause potential confusion among auditors. Commenters also suggested that the use of certain proposed language or certain proposed clarifications could result in potential confusion or unintended expansion of auditors' responsibilities. For example, one commenter suggested that requiring auditors to "keep in mind their role in

protecting investors" could encourage auditors to adopt an investor perspective when making judgments, which research highlights may be detrimental to audit quality.¹⁶³

These potential unintended consequences will be mitigated by changes to language in the adopted rule text or release discussion. Throughout the rulemaking process, the Board emphasized that eliminating restrictive provisions does not alter the core principles and responsibilities that are transitioned from the current standards to AS 1000. The Board removed the reference to "keep in mind their role in protecting investors" from the final standard based on changes made to paragraph .01 of the final standard. While the Board emphasized the investor protection obligation, the Board clarified that the emphasis does not create any new legal requirements. The Board does not believe that highlighting the auditor's existing obligation to protect investors will widen any expectation gap or decrease audit quality. Instead, the Board's goal was to heighten auditors' awareness and reinforce their existing obligation.

ii. Clarification of Engagement Partner Responsibilities

An unintended consequence of the amendment to clarify engagement partner responsibilities would occur if, contrary to the Board's expectation, some firms whose engagement partners currently do more than will be required to meet the minimum requirement for engagement partner review, do less in the future to merely meet the minimum requirement.¹⁶⁴

This potential unintended consequence will be mitigated by the extent to which engagement partners are aware that the engagement's performance is primarily their responsibility. Furthermore, in contrast to a highly specific minimum threshold, the Board noted that engagement partners under AS 1000 are bound to broad due professional care responsibilities that are less likely to incentivize engagement partners to merely meet a precise set of criteria

¹⁶¹ See, e.g., Lisa Bryant-Kutcher, Emma Yan Peng, and David P. Weber, *Regulating the Timing of Disclosure: Insights from the Acceleration of 10-K Filing Deadlines*, 32 *Journal of Accounting and Public Policy* 475 (2013); Colleen M. Boland, Scott N. Bronson, and Chris E. Hogan, *Accelerated Filing Deadlines, Internal Controls, and Financial Statement Quality: The Case of Originating Misstatements*, 29 *Accounting Horizons* 551 (2015); and Khaled Alsabab, *The 15-Day Debate and the Value of Early Release of Information: Evidence from 10-K Filings*, 42 *Journal of Accounting and Public Policy* 1 (2023).

¹⁶² See PCAOB Rel. No. 2023-001, at 50-51.

¹⁶³ See, e.g., Elizabeth C. Altiero, Yoon Ju Kang, and Mark E. Peecher, *Motivated Perspective Taking: Why Prompting Auditors to Take an Investor's Perspective Makes Them Treat Identified Audit Differences as Less Material*, 39 *Contemporary Accounting Research* 339 (2022) and Lei Dong, Lei Wang, and Wen-Wen Chien, *The Joint Effect of Supervisor Influence and Investor Perspective: Unintended Consequences on Assessing Accounting Estimates*, 37 *Managerial Auditing Journal* 151 (2022).

¹⁶⁴ See, e.g., Aobdia, *The Impact of the PCAOB* (finding that auditor effort declines subsequent to PCAOB inspections of engagements that do not receive a Part I finding).

without exceeding those criteria. In addition, economic reasons that generate enhanced performance in the first place, such as partner compensation, inspections, and litigation threat, help to mitigate this potential unintended consequence.

One commenter suggested that the amendment to clarify engagement partner responsibilities is reasonable and clear but could present unintended consequences by limiting firms' abilities to attract and retain talent, which could potentially result in lower audit quality if people leave the profession. The Board anticipates that the amendments related to engagement partner responsibilities will be unlikely to significantly affect firms' abilities to attract or retain talent, or to disincentivize individuals from being willing to serve as engagement partners because AS 1000 clarifies existing engagement partner responsibilities. As outlined in the rest of the economic analysis, the Board acknowledges that some marginal economic impacts could follow from these amendments, but does not agree with the commenter that those effects will be dramatic.

iii. Accelerating the Documentation Completion Date

Unintended consequences of accelerating the documentation completion date would occur if, contrary to the Board's expectation, (i) auditor time prior to the report release date that was previously spent focusing on audit procedures is now spent on assembling final workpapers or (ii) the archiving period results in higher costs that cause firms with paper-based documentation systems to exit the audit market or to not enter the audit market.

These potential unintended consequences will be mitigated by the current requirement that all necessary auditing procedures, review of those procedures, and collection of sufficient appropriate audit evidence be completed prior to the report release date.¹⁶⁵ Furthermore, if firms proactively sequence work, allocate resources, and incorporate other operating efficiencies, they should not experience substantial disruptions and should be able to handle the accelerated archiving deadline without major problems.

One commenter acknowledged that accelerating the documentation completion date may enhance audit quality overall but suggested that it could have an initial negative impact on audit quality as a result of accelerating the archiving process into the period

when many SEC practice audit professionals need to start working on other issuer audit engagements. Another commenter also acknowledged that accelerating the documentation completion date may enhance audit quality and said it may allow PCAOB inspections to begin sooner after completion of an audit, but issuers may have various filing deadlines or require extensions that will necessitate the full attention of professionals on those engagements. One commenter acknowledged that the acceleration is beneficial and appropriate, but suggested that beginning the inspection process earlier could be detrimental to audit quality because earlier inspections could cause auditors to reallocate their time to the inspection process and away from audits of financial statements. Consistent with the acknowledgements by these commenters, the Board continues to believe that accelerating the documentation completion date will be facilitated by the widespread use of electronic audit tools and audit software by most firms, which could mitigate potential operating disruptions that firms experience as they adjust to the accelerated date.

One commenter stressed the importance of the quality of audit documentation and noted that technology interruptions or cybersecurity matters could impact the ability of a firm to meet the accelerated deadline. However, the possibility of technology interruptions or cybersecurity matters could impact a firm's ability to meet any deadline. Another commenter reported that academic studies find there can be unintended consequences of additional regulation, including new costs associated with extensive audit documentation, auditors taking a "box-ticking" approach to extensive documentation requirements, and reduced auditor retention.¹⁶⁶ However, accelerating the documentation completion date does not add any new documentation requirements.

D. Alternatives Considered

During the formulation of the proposal and adoption of the final standard and related amendments, the Board considered a number of alternative approaches to the final

standard and related amendments the Board adopted, including those suggested by commenters.

1. Modernization of the Foundational Standards

The Board considered whether to update the foundational standards and keep them as individual standards, but the Board believes that combining the general principles and responsibilities into one standard is more logical and easier to navigate. This approach is also consistent with the approaches of other standard setters. For example, both the IAASB and the ASB address general responsibilities of the auditor in one standard (see IAASB's ISA 200 and ASB's AU-C 200).

The Board also considered whether to incorporate the requirements of AS 2815 into AS 1000, but believes that it is more logical to incorporate the requirements of AS 2815 into AS 2810 because both standards address requirements for concluding audit procedures. This approach also eliminates unnecessary cross-references between the two standards and makes the auditor's responsibilities easier to locate. AS 1000 includes a reference to AS 2810 for the auditor's responsibilities related to the evaluation of whether the financial statements are presented fairly, in all material respects, in conformity with the applicable financial reporting framework.

2. Clarification of Engagement Partner Responsibilities

With respect to engagement partner responsibilities, the Board considered retaining the language of AS 1010 that describes the use of judgment in the context of the partner's responsibilities for supervision. However, the Board believes that leveraging the requirements of AS 1201, a more recent standard, avoids potential confusion and aligns the engagement partner's responsibilities with Board-issued standards. Other alternatives to the amendments related to engagement partner responsibilities, including comments received, were considered as discussed above.

3. Accelerating the Documentation Completion Date

For the documentation completion date, the Board considered a length of time between the current 45-day period and the 14-day period, such as 21 days or 30 days. The Board believes that a shorter period of time may provide better protection for investors than a longer period: it could permit acceleration of PCAOB inspections and provide the strongest incentives for

¹⁶⁶ See, e.g., Colleen M. Boland, Brian E. Daugherty, and Denise Dickins, *Evidence of the Relationship between PCAOB Inspection Outcomes and the Use of Structured Audit Technologies*, 38 Auditing: A Journal of Practice & Theory 57 (2019) and Marion Brivot, Mélanie Roussy, and Maryse Mayer, *Conventions of Audit Quality: The Perspective of Public and Private Company Audit Partners*, 37 Auditing: A Journal of Practice & Theory 51 (2018).

¹⁶⁵ See AS 1215.15.

firms to implement operating efficiencies that may ultimately improve audit quality. Thus, in principle, a shorter documentation completion date could achieve more benefits than a longer period. The Board's assessment of existing firm practice as described above led it to believe that 14 days is feasible for firms and that a longer period could therefore be unnecessary and would erode the benefits that would otherwise be achieved.

Investor-related groups suggested the documentation completion date should be reduced to two days for all firms. The Board continues to believe 14 days is feasible for all firms while not being too restrictive for firms that may require more time. Another commenter asserted that the economic analysis did not adequately consider alternatives other than 14 days and that the analysis did not offer any alternatives to begin inspections earlier other than accelerating the documentation completion date. As noted above, the Board considered a length of time between the current 45-day period and the 14-day period. Moreover, the need to accelerate the documentation completion date is based on other considerations in addition to cases where the PCAOB would like to initiate inspections earlier. Another commenter asserted that firms' operating efficiencies are not the purview of the PCAOB. However, the need for the amendment is not based on operating efficiencies but may result in operating efficiencies that improve audit quality.

The Board also considered whether to specify different documentation completion dates for different classes of firms, based on specific firm characteristics that may make compliance with an accelerated documentation completion date especially challenging because of some practical obstacle or because of expenses that are common to that class of firms. For example, the Board considered specifying a longer documentation completion date for NAFs than for GNFs. However, as noted above, the Board believes that the 14-day period is a feasible period for all firms; the Board is not aware of any practical obstacle or expenses that will make compliance with a 14-day period especially challenging for all firms within a particular class. In contrast, a uniform and consistent archiving period for all firms would facilitate implementation and compliance, especially for audits that involve multiple firms that could be subject to different archiving periods. Finally, having a unified archiving date will

enable earlier PCAOB inspections across all registered firms.¹⁶⁷

Special Considerations for Audits of Emerging Growth Companies

Pursuant to Section 104 of the Jumpstart Our Business Startups ("JOBS") Act, rules adopted by the Board subsequent to April 5, 2012, generally do not apply to the audits of emerging growth companies ("EGCs"), as defined in Section 3(a)(80) of the Exchange Act, unless the SEC "determines that the application of such additional requirements is necessary or appropriate in the public interest, after considering the protection of investors, and whether the action will promote efficiency, competition, and capital formation."¹⁶⁸ As a result of the JOBS Act, the rules and related amendments to PCAOB standards that the Board adopts are generally subject to a separate determination by the SEC regarding their applicability to audits of EGCs.¹⁶⁹

To inform consideration of the application of auditing standards to audits of EGCs, PCAOB staff prepares a white paper annually that provides general information about characteristics of EGCs.¹⁷⁰ As of the November 15, 2022 measurement date, there were 3,031 companies¹⁷¹ that self-

¹⁶⁷ While the Board has not specified different documentation completion dates for different classes of firms, the extended effective date of the 14-day requirement for firms that issued audit reports with respect to 100 or fewer issuers during the calendar year ending December 31, 2024, will allow those firms more time to implement the revised requirement.

¹⁶⁸ See Public Law 112–106 (Apr. 5, 2012). Section 103(a)(3)(C) of Sarbanes-Oxley, as added by Section 104 of the JOBS Act, also provides that any rules of the Board requiring (1) mandatory audit firm rotation or (2) a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer (auditor discussion and analysis) shall not apply to an audit of an EGC. The new standard does not fall within either of these two categories.

¹⁶⁹ The Board provided this analysis of the impact on EGCs to assist the SEC in making the determination required under Section 104 to the extent that the requirements apply to "the audit of any emerging growth company" within the meaning of Section 104 of the JOBS Act.

¹⁷⁰ See PCAOB, *Characteristics of Emerging Growth Companies and Their Audit Firms* at November 15, 2022 (Feb. 20, 2024) ("EGC White Paper"), available at https://assets.pcaobus.org/pcaob-dev/docs/default-source/economicandriskanalysis/projectsother/documents/white-paper-on-characteristics-of-emerging-growth-companies-as-of-nov-15-2022.pdf?sfvrsn=a8294f3_2.

¹⁷¹ The EGC White Paper uses a lagging 18-month window to identify companies as EGCs. Please refer to the "Current Methodology" section in the EGC White Paper for details. Using an 18-month window enables staff to analyze the characteristics of a fuller population in the EGC White Paper but may tend to result in a larger number of EGCs being included for purposes of the present EGC analysis than

identified as EGCs and filed audited financial statements with the SEC between May 16, 2021, and November 15, 2022, that included an audit report signed by a firm.¹⁷²

As discussed in the proposal, the economic impacts of the standard and related amendments are generally applicable to audits of EGCs.¹⁷³ The amendment to accelerate the documentation completion date by reducing the maximum period for the auditor to assemble a complete and final set of audit documentation from 45 days to 14 days could impact the audits of EGCs more than the audits of non-EGCs to the extent that EGCs are more likely than non-EGCs to be audited by NAFs.¹⁷⁴ As discussed above, NAFs are expected to require more changes than GNFs in their sequencing of work, allocation of resources, and other operating practices to comply with the accelerated documentation completion date. Therefore, all else equal, both the benefits and costs of the amendments, including the amendment to accelerate the documentation completion date, may be higher for EGC audits than for non-EGC audits.

While both the benefits and costs of the amendment to accelerate the documentation completion date may be higher for EGC audits, the costs may be mitigated based on certain characteristics of EGCs. For example, to the extent that EGCs are smaller than non-EGCs, EGC audits may be less complex, which potentially facilitates expeditious assembly of the final workpapers.¹⁷⁵ In addition, to the extent that EGCs are audited by firms that issued audit reports with respect to 100 or fewer issuers during the calendar year ending December 31, 2024, the extended effective date of the amendment to accelerate the documentation completion date will allow those firms more time to

would alternative methodologies. For example, an estimate using a lagging 12-month window would exclude some EGCs that are delinquent in making periodic filings. An estimate as of the measurement date would exclude EGCs that have terminated their registration or that have exceeded the eligibility or time limits.

¹⁷² See EGC White Paper 17. Based on staff analysis as of the Nov. 15, 2022 measurement date, 86 percent of the 263 firms that issued audit reports for EGCs performed audits for both EGC and non-EGC issuers while 14 percent performed issuer audits only for EGCs.

¹⁷³ See PCAOB Rel. No. 2023–001, at 52–54.

¹⁷⁴ PCAOB staff analysis indicates that, compared to exchange-listed non-EGCs, exchange-listed EGCs are approximately 2.6 times as likely to be audited by an NAF (source: EGC White Paper and Standard & Poor's).

¹⁷⁵ See EGC White Paper, Figure 9 and Figure 12 (indicating that exchange-listed EGCs have lower market capitalization and revenue than exchange-listed non-EGCs).

implement the accelerated documentation completion date.¹⁷⁶ Moreover, as EGCs are not large accelerated filers (“LAFs”), the SEC Form 10–K filing deadline for EGCs is either 75 days after the fiscal year end for accelerated filers or 90 days for non-accelerated filers. This provides firms with an additional 15 days for accelerated filers or 30 days for non-accelerated filers, as compared to the time period for LAFs, to assemble the required final workpapers during a period that may be proportionately less busy.

The amendment to accelerate the documentation completion date could improve efficiency and capital formation for EGCs to the extent that the amendment reduces uncertainty about the reliability of an EGC’s financial statements via enhanced audit quality. Investors who are uncertain about the reliability of an EGC’s financial statements may require a larger risk premium that reduces the efficient allocation of capital or increases the cost of capital. Thus, any reduction of uncertainty via enhanced audit quality, including from firms’ implementation of operating efficiencies, could improve the efficiency of capital allocation, lower the cost of capital, and enhance capital formation for those EGCs.

The amendment to accelerate the documentation completion date could also impact competition in an EGC product market if any indirect costs to audited companies disproportionately affect EGCs relative to their competitors. For example, if EGCs are forced to raise prices in order to remain viable but their non-EGC competitors are not forced to raise prices, this may divert market share toward their non-EGC competitors. This could increase competition in markets where EGCs have a dominant market share and decrease competition in markets where EGCs have a less than dominant market share. However, the incentives for firms to pass costs onto EGCs may also be limited by competition for audits.

The proposal sought comments on the applicability of the proposed requirements to audits of EGCs. Several commenters agreed that the

requirements of AS 1000 should apply to the audits of EGCs. One commenter suggested that the audits of EGCs should be subject to stricter requirements because non-accelerated filers have a higher incidence of restatements and because small capitalization issuers have a higher proportion of equity owned by individual investors but less coverage by sell-side analysts.¹⁷⁷ However, the Board continues to believe the same standard and related amendments should apply to audits of EGCs and non-EGCs to avoid the potential for confusion that could accompany differences within firms’ policies and procedures with respect to audits of EGCs and non-EGCs.

Accordingly, and for the reasons explained above, the Board has requested that the Commission determine that it is necessary or appropriate in the public interest, after considering the protection of investors and whether the action will promote efficiency, competition, and capital formation, to apply the standard and related amendments to audits of EGCs.

III. Date of Effectiveness of the Proposed Rules and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the Board consents, the Commission will:

(A) By order approve or disapprove such proposed rules; or

(B) Institute proceedings to determine whether the proposed rules should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views and arguments concerning the foregoing, including whether the proposed rules are consistent with the requirements of Title I of 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/pcaob>); or
- Send an email to rule-comments@sec.gov. Please include PCAOB–2024–01 on the subject line.

Paper Comments

- Send paper comments in triplicate to Vanessa A. Countryman, Secretary, Securities and Exchange Commission, 100 F Street NE, Washington, DC 20549–1090.

All submissions should refer to PCAOB–2024–01. 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/pcaob>). Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rules that are filed with the Commission, and all written communications relating to the proposed rules 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 a.m. and 3 p.m. Copies of such filing will also be available for inspection and copying at the principal office of the PCAOB. 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 PCAOB–2024–01 and should be submitted on or before July 2, 2024.

For the Commission, by the Office of the Chief Accountant.¹⁷⁸

Vanessa A. Countryman,
Secretary.

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¹⁷⁶ See EGC White Paper 22. Based on staff analysis as of the Nov. 15, 2022 measurement date, U.S. firms audited 2,548 EGCs, of which 817 were audited by firms that issued audit reports for 100 or fewer issuer audit clients.

¹⁷⁷ See, e.g., Audit Analytics, *2021 Financial Restatements: A Twenty-One Year Review* (May 2022) and Garnet Roach, *Only Small Caps See Minority of Shares Held by Institutions, Research Shows*, IR Magazine (Jan. 18, 2022).

¹⁷⁸ 17 CFR 200.30–11(b)(1) and (3).



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Environmental Protection Agency

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Significant New Use Rules on Certain Chemical Substances (23–3.5e);
Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 721

[EPA-HQ-OPPT-2023-0328; FRL-11825-01-OCSPP]

RIN 2070-AB27

Significant New Use Rules on Certain Chemical Substances (23-3.5e)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing significant new use rules (SNURs) under the Toxic Substances Control Act (TSCA) for chemical substances that were the subject of premanufacture notices (PMNs) and are also subject to a TSCA Order. A SNUR requires persons who intend to manufacture (defined by statute to include import) or process a particular chemical substance for an activity that is identified as a significant new use in the SNUR to notify EPA at least 90 days before commencing that activity. The required notification initiates EPA's evaluation of the conditions of use identified in the notification to EPA. In addition, the manufacture or processing for the significant new use may not commence until EPA has conducted a review of the required notification, made an appropriate determination regarding that notification, and taken such actions as required by that determination.

DATES: Comments must be received on or before July 11, 2024.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA-HQ-OPPT-2023-0328, online at <https://www.regulations.gov>. Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Additional instructions on commenting and visiting the docket, along with more information about dockets generally, is available at <https://www.epa.gov/dockets>.

FOR FURTHER INFORMATION CONTACT:

For technical information: William Wysong, New Chemicals Division (7405M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460-0001; telephone number: (202) 564-4163; email address: wysong.william@epa.gov.

For general information: The TSCA-Hotline, ABVI-Goodwill, 422 South Clinton Ave., Rochester, NY 14620;

telephone number: (202) 554-1404; email address: TSCA-Hotline@epa.gov.

SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. What is the Agency's authority for taking this action?

TSCA section 5(a)(2) (15 U.S.C. 2604(a)(2)) authorizes EPA to determine that a use of a chemical substance is a "significant new use." EPA must make this determination by rule after considering all relevant factors, including the factors in TSCA section 5(a)(2) (see also the discussion in Unit II.).

B. What action is the Agency taking?

EPA is proposing SNURs for chemical substances that were the subject of PMNs as discussed in Unit III. These SNURs, if finalized as proposed, would require persons who intend to manufacture or process any of these chemical substances for an activity that is designated as a significant new use to notify EPA at least 90 days before commencing that activity.

C. Does this action apply to me?

1. General Applicability

This action applies to you if you manufacture, process, or use the chemical substances contained in this proposed rule. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Manufacturers or processors of one or more subject chemical substances (NAICS) codes 325 and 324110, *e.g.*, chemical manufacturing and petroleum refineries.

2. Applicability to Importers and Exporters

This action may also apply to certain entities through pre-existing import certification and export notification rules under TSCA (<https://www.epa.gov/tsc-import-export-requirements>).

Chemical importers are subject to the import provisions in TSCA section 13 (15 U.S.C. 2612), the requirements promulgated at 19 CFR 12.118 through 12.127 (see also 19 CFR 127.28), and the EPA policy in support of import certification at 40 CFR part 707, subpart B. Chemical importers must certify that the shipment of the chemical substance complies with all applicable rules and orders under TSCA, including

regulations issued under TSCA sections 5, 6, 7 and TSCA title IV.

Pursuant to 40 CFR 721.20, any persons who export or intend to export a chemical substance that is the subject of this proposed rule on or after July 11, 2024 are subject to the export notification provisions of TSCA section 12(b) (15 U.S.C. 2611(b)) and must comply with the export notification requirements in 40 CFR part 707, subpart D.

D. What are the incremental economic impacts of this action?

EPA has evaluated the potential costs of establishing significant new use notice (SNUN) reporting requirements for potential manufacturers (including importers) and processors of the chemical substances subject to these proposed SNURs. This analysis, which is available in the docket, is briefly summarized here.

1. Estimated Costs for SNUN Submissions

If a SNUN is submitted, costs are an estimated \$45,000 per SNUN submission for large business submitters and \$14,500 for small business submitters. These estimates include the cost to prepare and submit the SNUN (including registration for EPA's Central Data Exchange (CDX)), and the payment of a user fee. Businesses that submit a SNUN would be subject to either a \$37,000 user fee required by 40 CFR 700.45(c)(2)(ii) and (d), or, if they are a small business as defined at 13 CFR 121.201, a reduced user fee of \$6,480 (40 CFR 700.45(c)(1)(ii) and (d)) per fiscal year 2022. The costs of submission for SNUNs will not be incurred by any company unless a company decides to pursue a significant new use as defined in these SNURs. Additionally, these estimates reflect the costs and fees as they are known at the time of this rulemaking.

2. Estimated Costs for Export Notifications

EPA has also evaluated the potential costs associated with the export notification requirements under TSCA section 12(b) and the implementing regulations at 40 CFR part 707, subpart D. For persons exporting a substance that is the subject of a SNUR, a one-time notice to EPA must be provided for the first export or intended export to a particular country. The total costs of export notification will vary by chemical, depending on the number of required notifications (*i.e.*, the number of countries to which the chemical is exported). While EPA is unable to make any estimate of the likely number of

export notifications for the chemical substances covered by these SNURs, as stated in the accompanying economic analysis, the estimated cost of the export notification requirement on a per unit basis is approximately \$106.

E. What should I consider as I prepare my comments for EPA?

1. Submitting CBI

Do not submit CBI to EPA through email or <https://www.regulations.gov>. If you wish to include CBI in your comment, please follow the applicable instructions at <https://www.epa.gov/dockets/commenting-epa-dockets#rules> and clearly mark the information that you claim to be CBI. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR parts 2 and 703.

2. Tips for Preparing Your Comments

When preparing and submitting your comments, see the commenting tips at <https://www.epa.gov/dockets/commenting-epa-dockets>.

II. Background

This unit provides general information about SNURs. For additional information about EPA's new chemical program go to <https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca>.

A. Significant New Use Determination Factors

TSCA section 5(a)(2) states that EPA's determination that a use of a chemical substance is a significant new use must be made after consideration of all relevant factors, including:

- The projected volume of manufacturing and processing of a chemical substance.
- The extent to which a use changes the type or form of exposure of human beings or the environment to a chemical substance.
- The extent to which a use increases the magnitude and duration of exposure of human beings or the environment to a chemical substance.
- The reasonably anticipated manner and methods of manufacturing, processing, distribution in commerce, and disposal of a chemical substance.

In determining what would constitute a significant new use for the chemical substances that are the subject of these SNURs, EPA considered relevant information about the toxicity of the chemical substances, and potential human exposures and environmental releases that may be associated with the substances, in the context of the four bulleted TSCA section 5(a)(2) factors

listed in this unit and discussed in Unit III.

These proposed SNURs include PMN substances that are subject to Orders issued under TSCA section 5(e)(1)(A), as required by the determinations made by EPA under TSCA section 5(a)(3)(B). The TSCA Orders require protective measures to limit exposures or otherwise mitigate the potential unreasonable risk. The proposed SNURs identify as significant new uses any manufacturing, processing, use, distribution in commerce, or disposal that does not conform to the restrictions imposed by the underlying TSCA Orders, consistent with TSCA section 5(f)(4).

B. Rationale and Objectives of the SNURs

1. Rationale

Under TSCA, no person may manufacture a new chemical substance or manufacture or process a chemical substance for a significant new use until EPA makes a determination as described in TSCA section 5(a) and takes any required action. The issuance of a SNUR is not a risk determination itself, only a notification requirement for "significant new uses," so that the Agency has the opportunity to review the SNUN for the significant new use and make a TSCA section 5(a)(3) risk determination.

During review of the PMNs submitted for the chemical substances, EPA concluded that regulation was warranted under TSCA section 5(e), pending the development of information sufficient to make reasoned evaluations of the health or environmental effects of the chemical substances. The basis for such findings is outlined in Unit IV. Based on these findings, TSCA section 5(e) Orders requiring the use of appropriate exposure controls were negotiated with the PMN submitters. As a general matter, EPA believes it is necessary to follow the TSCA Orders with a SNUR that identifies the absence of those protective measures as significant new uses to ensure that all manufacturers and processors—not just the original submitter—are held to the same standard.

2. Objectives

EPA is proposing these SNURs because the Agency wants:

- To identify as significant new uses any manufacturing, processing, use, distribution in commerce, or disposal that does not conform to the restrictions imposed by the underlying TSCA Orders, consistent with TSCA section 5(f)(4).
- To have an opportunity to review and evaluate data submitted in a SNUN

before the submitter begins manufacturing or processing a listed chemical substance for the described significant new use.

- To be obligated to make a determination under TSCA section 5(a)(3) regarding the use described in the SNUN, under the conditions of use. The Agency will either determine under TSCA section 5(a)(3)(C) that the significant new use is not likely to present an unreasonable risk, including an unreasonable risk to a potentially exposed or susceptible subpopulation identified as relevant by the Administrator under the conditions of use, or make a determination under TSCA section 5(a)(3)(A) or (B) and take the required regulatory action associated with the determination, before manufacture or processing for the significant new use of the chemical substance can occur.

Issuance of a proposed SNUR for a chemical substance does not signify that the chemical substance is listed on the TSCA Chemical Substance Inventory (TSCA) Inventory. Guidance on how to determine if a chemical substance is on the TSCA Inventory is available at <https://www.epa.gov/tsca-inventory>.

C. Significant New Uses Claimed as CBI

EPA is proposing to establish certain significant new uses which have been claimed as CBI subject to Agency confidentiality regulations at 40 CFR part 2 and 40 CFR part 720, subpart E. Absent a final determination or other disposition of the confidentiality claim under 40 CFR part 2 procedures, EPA is required to keep this information confidential. EPA promulgated a procedure to deal with the situation where a specific significant new use is CBI, at 40 CFR 721.11.

Under these procedures a manufacturer or processor may request EPA to determine whether a specific use would be a significant new use under the rule. The manufacturer or processor must show that it has a *bona fide* intent to manufacture or process the chemical substance and must identify the specific use for which it intends to manufacture or process the chemical substance. If EPA concludes that the person has shown a *bona fide* intent to manufacture or process the chemical substance, EPA will tell the person whether the use identified in the *bona fide* submission would be a significant new use under the rule. Since most of the chemical identities of the chemical substances subject to these SNURs are also CBI, manufacturers and processors can combine the *bona fide* submission under the procedure in 40 CFR 721.11 into a single step.

If EPA determines that the use identified in the *bona fide* submission would not be a significant new use, *i.e.*, the use does not meet the criteria specified in the rule for a significant new use, that person can manufacture or process the chemical substance so long as the significant new use trigger is not met. In the case of a production volume trigger, this means that the aggregate annual production volume does not exceed that identified in the *bona fide* submission to EPA. Because of confidentiality concerns, EPA does not typically disclose the actual production volume that constitutes the use trigger. Thus, if the person later intends to exceed that volume, a new *bona fide* submission would be necessary to determine whether that higher volume would be a significant new use.

D. Applicability of General Provisions

General provisions for SNURs appear in 40 CFR part 721, subpart A. These provisions describe persons subject to SNURs, recordkeeping requirements, exemptions to reporting requirements, and applicability of the rule to uses occurring before the effective date of the rule.

Pursuant to 40 CFR 721.1(c), persons subject to SNURs must comply with the same requirements and EPA regulatory procedures as submitters of PMNs under TSCA section 5(a)(1)(A). In particular, these requirements include the information submission requirements of TSCA sections 5(b) and 5(d)(1), the exemptions authorized by TSCA sections 5(h)(1), 5(h)(2), 5(h)(3), and 5(h)(5) and the regulations at 40 CFR part 720. In addition, provisions relating to user fees appear at 40 CFR part 700.

Once EPA receives a SNUN, EPA must either determine that the conditions of use is not likely to present an unreasonable risk of injury under the conditions of use for the chemical substance or take such regulatory action as is associated with an alternative determination under TSCA section 5 before the manufacture (including import) or processing for the significant new use can commence. If EPA determines that the conditions of use of the chemical substance is not likely to present an unreasonable risk, EPA is required under TSCA section 5(g) to publish a statement of EPA's findings in the **Federal Register**.

As discussed in Unit I.C.2., persons who export or intend to export a chemical substance identified in a proposed or final SNUR are subject to the export notification provisions of TSCA section 12(b), and persons who import a chemical substance identified in a final SNUR are subject to the TSCA

section 13 import certification requirements. See also <https://www.epa.gov/tsca-import-export-requirements>.

E. Applicability of the Proposed SNURs to Uses Occurring Before the Effective Date of the Final Rule

To establish a significant new use, EPA must determine that the use is not ongoing. The chemical substances subject to this proposed rule have undergone premanufacture review and received determinations under TSCA section 5(a)(3)(C). TSCA Orders have been issued for these substances and the PMN submitters are required by the TSCA Orders to submit a SNUN before undertaking activities which would be designated as significant new uses in these SNURs. Additionally, the identities of many of the chemical substances subject to this proposed rule have been claimed as confidential per 40 CFR 720.85, further reducing the likelihood that another party would manufacture or process the substances for an activity that would be designated as a significant new use. Based on this, the Agency believes that it is highly unlikely that any of the significant new uses identified in Unit III are ongoing.

When the chemical substances identified in Unit III are added to the TSCA Inventory, EPA recognizes that, before the rule is effective, other persons might engage in a use that has been identified as a significant new use. Persons who begin manufacture or processing of the chemical substances for a significant new use identified on or after the designated cutoff date specified in Unit III.A. would have to cease any such activity upon the effective date of the final rule. To resume their activities, these persons would have to first comply with all applicable SNUR notification requirements and EPA would have to take action under TSCA section 5 allowing manufacture or processing to proceed.

F. Important Information About SNUN Submissions

1. SNUN Submissions

SNUNs must be submitted on EPA Form No. 7710–25, generated using e-PMN software, and submitted to the Agency in accordance with the procedures set forth in 40 CFR 720.40 and 721.25. E-PMN software is available at <https://www.epa.gov/reviewing-new-chemicals-under-toxic-substances-control-act-tsca>.

2. Development and Submission of Information

EPA recognizes that TSCA section 5 does not require development of any particular new information (*e.g.*, generating test data) before submission of a SNUN. There is an exception: If a person is required to submit information for a chemical substance pursuant to a rule, order or consent agreement under TSCA section 4, then TSCA section 5(b)(1)(A) requires such information to be submitted to EPA at the time of submission of the SNUN.

In the absence of a rule, TSCA Order, or consent agreement under TSCA section 4 covering the chemical substance, persons are required only to submit information in their possession or control and to describe any other information known to or reasonably ascertainable by them (see 40 CFR 720.50). However, upon review of PMNs and SNUNs, the Agency has the authority to require appropriate testing. To assist with EPA's analysis of the SNUN, submitters are encouraged, but not required, to provide the potentially useful information identified for the chemical substance in Unit III.C.

EPA strongly encourages persons, before performing any testing, to consult with the Agency pertaining to protocol selection. Furthermore, pursuant to TSCA section 4(h), which pertains to reduction of testing in vertebrate animals, EPA encourages consultation with the Agency on the use of alternative test methods and strategies (also called New Approach Methodologies, or NAMs), if available, to generate the recommended test data. EPA encourages dialog with Agency representatives to help determine how best the submitter can meet both the data needs and the objective of TSCA section 4(h). For more information on alternative test methods and strategies to reduce vertebrate animal testing, visit <https://www.epa.gov/assessing-and-managing-chemicals-under-tsca/alternative-test-methods-and-strategies-reduce>.

The potentially useful information described in Unit III.C. for these chemical substances may not be the only means of providing information to evaluate the chemical substance associated with the significant new uses. However, submitting a SNUN without any information may increase the likelihood that EPA will take action under TSCA sections 5(e) or 5(f). EPA recommends that potential SNUN submitters contact EPA early enough so that they will be able to conduct the appropriate tests to provide useful

information with their SNUN submission.

SNUN submitters should be aware that EPA will be better able to evaluate SNUNs which provide detailed information on the following:

- Human exposure and environmental release that may result from the significant new use of the chemical substances.

III. Chemical Substances Subject to These Proposed SNURs

A. What is the designated cutoff date for ongoing uses?

EPA designates June 11, 2024 as the cutoff date for determining whether the new use is ongoing. This designation is explained in more detail in Unit II.D.

B. What information is provided for each chemical substance?

For each chemical substance identified in Unit III.C., EPA provides the following information:

- PMN number (the proposed CFR citation assigned in the regulatory text section of this document).
- Chemical name (generic name, if the specific name is claimed as CBI).
- Chemical Abstracts Service Registry Number (CASRN) (if assigned for non-confidential chemical identities).
- Effective date of and basis for the TSCA Order.
- Potentially useful information.

The regulatory text section of the proposed rule specifies the activities designated as significant new uses. Certain new uses, including production volume limits and other uses designated in the proposed rules, may be claimed as CBI.

These proposed rules include PMN substances that are subject to orders issued under TSCA section 5(e)(1)(A), as required by the determinations made under TSCA section 5(a)(3)(B). Those TSCA Orders require protective measures to limit exposures or otherwise mitigate the potential unreasonable risk. The proposed SNURs identify as significant new uses any manufacturing, processing, use, distribution in commerce, or disposal that does not conform to the restrictions imposed by the underlying TSCA Orders, consistent with TSCA section 5(f)(4).

C. Which chemical substances are subject to the proposed SNURs in this document?

The substances subject to the proposed rules in this document are as follows:

PMN Number (Proposed CFR Citation): P-20-96 (40 CFR 721.11829)

Chemical Name: Unsaturated dicarboxylic acid polymer with 2-(dialkylamino)alkyl-alkyl-alkanoate, N,N-dialkyl-alkene amide, 2-propenamide and salt of alkyl-substituted alkene sulfonate (generic).

CASRN: Not available.

Effective Date of TSCA Order: November 8, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be in a papermaking process. Based on a structural alert for aliphatic amines, the acid moieties, and a confidential residual substance, EPA has identified concerns for skin, eye, and respiratory tract irritation. Based on comparison to analogous polyamphoteric polymers, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 490 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified gas/vapor respirator with an APF of at least 10 where there is a potential for inhalation exposure;
- No manufacture of the PMN substance unless the percentage of the confidential reactant listed in the Order represents 10% or less (by weight) of the PMN substance;
- No release of the PMN substance resulting in surface water concentrations that exceed 490 ppb; and
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity testing may be potentially useful to characterize the environmental effects of the PMN substance. Although the Order does not require these tests,

the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-21-2 (40 CFR 721.11830)

Chemical Name: Octadecanoic acid, 12-hydroxy-, polymer with aziridine, 2-oxepanone and tetrahydro-2H-pyran-2-one, reaction products with disubstituted heteropolycycle (generic).

CASRN: Not available.

Effective Date of TSCA Order: October 4, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a polymer in coatings. Based on a structural alert for aliphatic amines, EPA has identified concerns for lung effects (cationic binding) and irritation to the skin, eyes, and respiratory tract. Based on comparison to analogous polycationic polymers, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 50 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No use of the PMN substance in consumer products;
- No release of the PMN substance, or any waste stream containing the PMN substance, in surface water concentrations that exceed 50 ppb;
- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified respirator with an APF of at least 50 where there is a potential for inhalation exposure during non-spray applications;
- Use of a NIOSH-certified respirator with an APF of at least 10,000 where there is a potential for inhalation exposure during spray applications;
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has

determined that the results of skin irritation, eye irritation/corrosion, pulmonary effects, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order's restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-21-19 (40 CFR 721.11831)

Chemical Name: Ethyl 4-alkyl-2-oxocycloalkancarboxylate (generic).

CASRN: Not available.

Effective Date of TSCA Order: November 17, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a fragrance ingredient. Based on submitted test data on PMN substance, EPA has identified concerns for acute neurotoxicity and kidney effects, and EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 460 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No use of the PMN substance other than as a fragrance ingredient for making fragrance oils by blending (mixing) with other fragrance ingredients;
- No use of the PMN substance at a concentration of 0.5% (by weight) or greater in consumer products;
- No domestic manufacture of the PMN substance (*i.e.*, import only);
- Use of personal protective equipment where there is a potential for dermal exposure; and
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a "significant new use" the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity testing may be potentially

useful to characterize the environmental effects of the PMN substances. Although the Order does not require these tests, the Order's restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Numbers (Proposed CFR Citations): P-21-48 (40 CFR 721.11832), P-21-130 (40 CFR 721.11833), P-21-131 (40 CFR 721.11834), P-21-177 (40 CFR 721.11835), P-21-204 (40 CFR 721.11836), and P-22-12 (40 CFR 721.11837)

Chemical Names: Sulfonium, tricarboxylic-, polyfluoropolyhydro-2,2-dicarboxylic -4,7-methano-1,3-benzodioxole-5-alkanesulfonate (1:1) (generic) (P-21-48), Sulfonium, tricarboxylic-, 2-[3,5-bis(haloalkyl)phenyl]-.alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2-alkyl-4,7-alkano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic) (P-21-130), Sulfonium, tricarboxylic-, 2-(4-alkoxyhalocarboxymonocyclic)-.alpha., .alpha., .beta., .beta.-polyhalopolyhydro-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic) (P-21-131), Sulfonium, monocarboxylicbisarylpolychloroalkyl, .alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2,2-diaryl-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic) (P-21-177), Sulfonium, bis(3,4-polyhalocarboxylic)aryl-, .alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2,2-diaryl-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic) (P-21-204), and Sulfonium, tricarboxylic-, 2-heteroatom-substituted-4-(halocarboxylic)carboxylate (1:1) (generic) (P-22-12).

CASRNs: Not available.

Effective Date of TSCA Order: December 22, 2022.

Basis for TSCA Order: The PMNs state that the generic (non-confidential) use of the PMN substances will be for photolithography. Based on the physical/chemical properties of the PMN substances (as described in the New Chemical Program's PBT category at 64 FR 60194; November 1999) and in the absence of data, the PMN substances and photolysis products are potentially persistent, bioaccumulative, and toxic (PBT) chemicals. EPA estimates that the PMN substances will persist in the environment for more than two months and that their potential to bioaccumulate is unknown. EPA estimates that the photolysis products will persist in the environment for more than two months and estimates a bioaccumulation factor of greater than

or equal to 1,000. Based on the reactivity of the PMN substances, EPA has identified concerns for photosensitization. Based on information provided in the SDS and data on analogues, EPA has also identified concerns for irritation to the skin, eyes, and respiratory tract. Based on data on sulfonium compounds, EPA has also identified concerns for acute toxicity, irritation to the skin, eyes, and respiratory tract, eye corrosion, ocular lethality, neurological effects, and systemic effects for the sulfonium cation of the PMN substances. Based on comparison to analogous substances, EPA has also identified concerns for mutagenicity. Based on analogue data, EPA has also identified concerns for thyroid, liver, and reproductive (developmental) toxicity for the anion for PMNs P-21-48, P-21-130, P-21-131, P-21-177, and P-21-204. Based on test data on salicylic acid and sodium salicylate and a structural alert for phenols, EPA has also identified concerns for acute toxicity, eye irritation, neurotoxicity, reproductive and developmental effects for P-22-12. Based on protein binding alert for benzyl phenyl ethers, EPA has also identified concerns for skin sensitization for P-22-12. Based on data on a potential incineration product, EPA has identified concerns for local and systemic effects. Based on insufficient information, the PMN substance has unknown toxicity to aquatic organisms. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substances may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No manufacture of any of the PMN substances beyond the time limits specified in the Order without submittal to EPA the results of certain testing described in the Testing section of the Order;
- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS;
- No modification of the processing or use of the PMN substances in any way that generates a vapor, dust, mist, or aerosol in a non-enclosed process;
- Use of the PMN substances only for the confidential use stated in the Order;
- No domestic manufacture of the PMN substances (*i.e.*, import only);

- Import of the PMN substances only in solution, or in any form in sealed containers weighing 5 kilograms or less; and

- No exceedance of the confidential annual importation volumes stated in the Order.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information about the physical/chemical properties, fate, bioaccumulation, environmental hazard, and human health effects of the PMN substances may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. The submitter has agreed not to exceed the time limits specified in the Order without performing the required Tier I and Tier II testing outlined in the Testing section of the Order.

PMN Number (Proposed CFR Citation): P-21-55 (40 CFR 721.11838)

Chemical Name: Fatty acids, reaction products with polyamine-polyacid polymer and fatty acid (generic).

CASRN: Not available.

Effective Date of TSCA Order: March 29, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as an adhesive used for coating formulations. Based on structural alert for aliphatic amines, EPA has identified concerns for irritation to the skin, eyes, and respiratory tract. Based on a potential metabolite and confidential residual, EPA has also identified concerns for systemic (body weight, adrenal, and clinical chemistry), reproductive, and developmental effects. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Manufacture of the PMN substance only in a manner that results in an amine value of no more than 127 mg KOH/g;
- Use of a NIOSH-certified particulate respirator with an APF of at least 10 where there is a potential for inhalation exposure;
- Use of personal protective equipment where there is a potential for dermal exposure; and

- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of skin irritation, eye damage, and specific target organ toxicity testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Numbers (Proposed CFR Citations): P-21-71 (40 CFR 721.11839) and P-21-72 (40 CFR 721.11840)

Chemical Names: Poly[oxy(methyl-1,2-ethandiyl)], .alpha.-(dithiocarboxy)-.omega.-(1-methylethoxy)-, sodium salt (1:1) (P-21-71) and Poly[oxy(methyl-1,2-ethandiyl)], .alpha.-(dithiocarboxy)-.omega.-butoxy-, sodium salt (1:1) (P-21-72).

CASRNs: 2304726-53-0 (P-21-71) and 2304726-56-3 (P-21-72).

Effective Date of TSCA Order: October 5, 2022.

Basis for TSCA Order: The PMNs state that the uses will be as flotation aids in sulfide ore mining. Based on surfactant properties, EPA has identified concerns for lung effects and skin and eye irritation. Based on data on carbon disulfide, EPA has also identified concerns for neurotoxicity and systemic, reproductive, and developmental effects for the hydrolysis product. Based on comparison to analogous esters, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 350 ppb (P-21-71) and 150 ppb (P-21-72). The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substances may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;

- Use of a NIOSH-certified respirator with an APF of at least 10 where there is a potential for inhalation exposure;

- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS;

- No use of the PMN substances other than as flotation aids in sulfide ore mining at mines with valid permits (State, Federal, or Tribal) for operations and waste handling;

- No domestic manufacture of the PMN substances (*i.e.*, import only); and
- No release of the PMN substances resulting in surface water concentrations that exceed 150 ppb.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity, developmental toxicity, eye damage, neurotoxicity, reproductive toxicity, skin irritation, specific target organ toxicity, and pulmonary effects testing may be potentially useful to characterize the health and environmental effects of the PMN substances. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-21-73 (40 CFR 721.11841)

Chemical Name: 1,4-Cyclohexanedicarboxylic acid, 1,4-dinonyl ester, branched and linear.

CASRN: 2449089-78-3.

Effective Date of TSCA Order: September 1, 2022.

Basis for TSCA Order: The PMN states that the use will be as a plasticizer in PVC articles like roofing membranes, flooring, or coated fabrics. Based on the potential hydrolysis product, EPA has identified concerns for reproductive and developmental effects. Based on test data on the PMN substance and comparison to neutral organic substances, EPA predicts the PMN substance may be toxic to aquatic organisms and has unknown toxicity to sediment dwelling environmental organisms. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information

to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- No processing or use of the PMN substance in a consumer product;
- No processing or use of the PMN substance other than as a plasticizer in polyvinyl chloride (PVC) articles;
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS;
- No release of the PMN substance, or any waste stream containing the PMN substance, into water or into any environmental media destined for water.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity testing may be potentially useful to characterize the environmental effects of the PMN substance. Although the Order does not require this test, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-21-74 (40 CFR 721.11842)

Chemical Name: 1,3-Butadiene, homopolymer, hydrogenated, 2-(ethenyl)ethyl-terminated.

CASRN: 2511154-73-5.

Effective Date of TSCA Order: March 28, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a resin component of an adhesive formulation. Based on potential epoxidation of the terminal C=C bonds, EPA has identified concerns for dermal and respiratory sensitization, reproductive and developmental effects, genotoxicity, and carcinogenicity. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To

protect against these risks, the Order requires:

- No use of the PMN substance in consumer products;
- No manufacture, processing, or use of the PMN substance in any manner that results in inhalation exposure;
- Use of the PMN substance only for the confidential use listed in the Order;
- No release of the PMN substance, or any waste stream containing the PMN substance, into waters of the United States;
- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of sensitization, germ cell mutagenicity, specific target organ toxicity, reproductive toxicity, and developmental toxicity testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Numbers (Proposed CFR Citations): P-21-89 (40 CFR 721.11843) and P-21-90 (40 CFR 721.11844)

Chemical Names: Lignin, modified, reaction products with alkylamine by-products, hydrochlorides (generic) (P-21-89) and Lignin, modified, reaction products with alkylamine by-products (generic) (P-21-90).

CASRNs: Not available.

Effective Date of TSCA Order: July 25, 2022.

Basis for TSCA Order: The PMNs state that the generic (non-confidential) uses will be as an emulsifier (P-21-89) and a component in paving formulations (P-21-90). Based on the cationic binding of amines to lung membranes, EPA has identified concerns for lung effects. Based on analogue data, EPA has also identified concerns for corrosion to the skin and eyes for P-21-90. Based on comparison to analogous polycationic polymers, EPA predicts toxicity to

aquatic organisms may occur at concentrations that exceed 2 ppb (P-21-89). Based on comparison to analogous polyamphoteric polymers, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 12 ppb (P-21-90). The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substances may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure to P-21-90;
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS;
- No manufacture, processing, or use in any manner that results in inhalation exposure;
- No manufacture, processing, or use in any manner that results in air releases to the environment except during loading or unloading of transport containers;
- No release of PMN P-21-89 resulting in surface water concentrations that exceed 2 ppb; and
- No release of PMN P-21-90 resulting in surface water concentrations that exceed 12 ppb.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity and specific target organ toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substances. EPA has also determined that the results of skin corrosion and serious eye damage testing may be potentially useful to characterize the health effects of P-21-90. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-21-124 (40 CFR 721.11845)

Chemical Name: Sulfonium, triphenyl-, salt with fluoroalkyl 5-

sulfobicyclo[2.2.1]heptane carboxylate (1:1) (generic).

CASRN: Not available.

Effective Date of TSCA Order: December 22, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use of the PMN substance will be for photolithography. Based on the physical/chemical properties of the PMN substance (as described in the New Chemical Program's PBT category at 64 FR 60194; November 1999) and in the absence of data, the PMN substance is a potentially persistent, bioaccumulative, and toxic (PBT) chemical. EPA estimates that the PMN substance may potentially persist in the environment for more than six months and estimates a bioaccumulation factor of greater than or equal to 1,000. Based on the reactivity of the PMN substance, EPA has identified concerns for photosensitization. Based on data on sulfonium compounds, EPA has also identified concerns for acute toxicity, irritation to the skin, eyes, and respiratory tract, eye corrosion, ocular lethality, neurological effects, and systemic effects for the sulfonium cation of the PMN substance. Based on comparison to analogous substances, EPA has also identified concerns for genetic toxicity. Based on perfluoro analogue data, EPA has also identified concerns for thyroid, liver, and reproductive (developmental) toxicity for the anion. Based on data on a potential incineration product, EPA has also identified concerns for local and systemic effects. Based on insufficient information, the PMN substance has unknown toxicity to aquatic organisms. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No manufacture of the PMN substance beyond the time limits specified in the Order without submittal to EPA the results of certain testing described in the Testing section of the Order;
- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS;
- No modification of the processing or use of the PMN substance in any way

that generates a vapor, dust, mist, or aerosol in a non-enclosed process;

- Use of the PMN substance only as an onium salt that generates strong or weak acid in lithography process;
- No domestic manufacture of the PMN substance (*i.e.*, import only);
- Import of the PMN substance only in solution, or in any form in sealed containers weighing 5 kilograms or less; and
- No exceedance of the confidential annual importation volume listed in the Order.

The proposed SNUR would designate as a "significant new use" the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information about the physical/chemical properties, fate, bioaccumulation, environmental hazard, and human health effects of the PMN substance may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. The submitter has agreed not to exceed the time limits specified in the Order without performing the required Tier I and Tier II testing outlined in the Testing section of the Order.

PMN Number (Proposed CFR Citation): P-21-137 (40 CFR 721.11846)

Chemical Name: Triazine-trione, tris(isocyanatoalkyl)-, polymer with substituted diisocyanato alkylcarbomonocycle, hydro-hydroxypoly(oxyalkanediyl) and hydro-hydroxypoly[oxy(alkyl-alkanediyl)], aliphatic alkyl amine-blocked (generic).

CASRN: Not available.

Effective Date of TSCA Order: August 3, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as an industrial additive. Based on information in the SDS, comparison to analogous chemical substances, and test data on a residual, EPA has identified concerns for eye, skin, and respiratory irritation, eye and skin corrosion, acute toxicity, acute neurotoxicity, systemic effects, portal-of-entry effects, mutagenicity, and reproductive effects. Based on the potential of the PMN substance as a crosslinker, EPA has also identified concerns for skin sensitization. Based on comparison to analogous substituted ureas, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 15 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence

of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No use of the PMN substance in consumer products;
- No manufacture, processing, or use of the PMN substance in any manner that results in inhalation exposure;
- No release of the PMN substance, or any waste stream containing the PMN substance, in surface water concentrations that exceed 15 ppb;
- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a "significant new use" the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of reproductive toxicity, specific target organ toxicity, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order's restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-21-138 (40 CFR 721.11847)

Chemical Name: Lithium metal oxide (generic).

CASRN: Not available.

Effective Date of TSCA Order: October 31, 2022.

Basis for TSCA Order: The PMN states that the use will be as an electrode material for use in the manufacture of batteries. Based on the physical/chemical properties of the PMN substance and comparison to analogous respirable, poorly soluble particulates, EPA has identified concerns for lung effects (lung overload). Based on comparison to analogous chemical substances, EPA has also identified concerns for systemic, reproductive, and developmental effects. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I),

based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified particulate respirator with an APF of at least 1,000 if the dust control capture and reduction rate is at less than 90% where there is a potential for inhalation exposure;
- Use of a NIOSH-certified particulate respirator with an APF of at least 50 if the dust control capture and reduction rate is at least 90% where there is a potential for inhalation exposure;
- No domestic manufacture of the PMN substance (*i.e.*, import only);
- No disposal of the PMN substance or waste streams containing the PMN substance other than by landfill or incineration;
- No use of the PMN substance in a consumer product;
- No use of the PMN substance other than in the manufacture of batteries; and
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of pulmonary testing may be potentially useful to characterize the health effects of the PMN substance. Although the Order does not require this test, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P–21–140 (40 CFR 721.11848)

Chemical Name: Soybean oil, oleic acid-high, epoxidized.

CASRN: 2410202–82–1.

Effective Date of TSCA Order: September 1, 2022.

Basis for TSCA Order: The PMN states that the use will be as a chemical intermediate to prepare acrylate-containing oil, which is subsequently polymerized to prepare a viscosity modifier for asphalt. Based on analogous epoxides, EPA has identified

concerns for reproductive effects and carcinogenicity. Based on OECD QSAR Toolbox results and test data for a functional analogue, 4-vinylcyclohexene diepoxide, EPA has also identified concerns for carcinogenicity. Based on test data for an analogue, epoxidized soybean oil, EPA has also identified concerns for systemic effects and reproductive effects. Based on OECD QSAR Toolbox identification as a respiratory sensitizer, the new chemical substance having bifunctional reactive groups which can crosslink proteins, and the respiratory tract not having a stratum corneum protective layer like the skin to inhibit absorption, EPA has also identified concerns for respiratory sensitization. Based on insufficient information, toxicity to sediment-dwelling organisms is unknown. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- No release of the PMN substance, or any waste stream containing the PMN substance, into waters of the United States;
- No use of the PMN substance other than as a chemical intermediate to prepare acrylate-containing oil, which is subsequently polymerized to prepare a viscosity modifier for asphalt;
- No manufacture, processing, or use of the PMN substance in any manner that results in inhalation exposure; and
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of specific target organ toxicity, skin irritation, eye irritation/corrosion, reproductive toxicity, developmental toxicity, carcinogenicity, and sediment organism toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN

substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P–21–180 (40 CFR 721.11849)

Chemical Name: Sulfonium, (halocarbomonocycle)diphenyl-, salt with 1-heterosubstituted-2-methylalkyl trihalobenzoate (1:1) (generic).

CASRN: Not available.

Effective Date of TSCA Order: December 20, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use of the PMN substance will be for microlithography for electronic device manufacturing. Based on the physical/chemical properties of the PMN substance (as described in the New Chemical Program’s PBT category at 64 FR 60194; November 1999) and the absence of data, the PMN substance is a potentially persistent, bioaccumulative, and toxic (PBT) chemical. EPA estimates that the PMN substance will persist in the environment for more than six months and the bioaccumulation potential is unknown and that the cation photolysis product has the potential to bioaccumulate and be persistent in the environment. Based on the reactivity of the PMN substance, EPA has identified concerns for photosensitization. Based on data on sulfonium compounds and information provided in the SDS, EPA has also identified concerns for acute toxicity, irritation to the skin, eyes, and respiratory tract, eye corrosion, ocular lethality, neurological effects, and systemic effects for the sulfonium cation of the PMN substance. Based on comparison to analogous substances, EPA has also identified concerns for mutagenicity. Based on analogue data and the OECD QSAR Toolbox, EPA has also identified concerns for thyroid, liver, and reproductive (developmental) toxicity and skin sensitization for the anion. Based on data on a potential incineration product, EPA has identified concerns for local and systemic effects. Based on insufficient information, the PMN substance has unknown toxicity to aquatic organisms. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No manufacture of the PMN substance beyond the time limits specified in the Order without submittal to EPA the results of certain testing described in the Testing section of the Order;

- Use of personal protective equipment where there is a potential for dermal exposure;

- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS;

- No modification of the processing or use of the PMN substance in any way that generates a vapor, dust, mist, or aerosol in a non-enclosed process;

- Use of the PMN substance only for the confidential use stated in the Order;

- No domestic manufacture of the PMN substance (*i.e.*, import only);

- Import of the PMN substance only in solution, or in any form in sealed containers weighing 5 kilograms or less; and

- No exceedance of the confidential annual importation volume listed in the Order.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information about the physical/chemical properties, fate, bioaccumulation, environmental hazard, and human health effects of the PMN substance may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. The submitter has agreed not to exceed the time limits specified in the Order without performing the required Tier I and Tier II testing outlined in the Testing section of the Order.

PMN Number (Proposed CFR Citation): P-21-199 (40 CFR 721.11850)

Chemical Name: 1,6-Disubstituted hexane (generic).

CASRN: Not available.

Effective Date of TSCA Order: November 7, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a processing aid. Based on comparison to analogous chemical substances, EPA has identified concerns for acute toxicity, irritation to the skin, eyes, and respiratory tract, respiratory and skin sensitization, neurotoxicity, systemic effects, genotoxicity, reproductive, and developmental effects. Based on structural alerts, EPA has also identified concerns for

carcinogenicity. Based on comparison to analogous chemical substances, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 23 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;

- No release of the PMN substance, or any waste steam containing the PMN substance, into waters of the United States;

- No manufacture, processing, or use of the PMN substance in any manner that results in inhalation exposure;

- No disposal of the PMN substance or waste streams containing the PMN substance other than by hazardous waste incineration;

- No use of the PMN substance in a consumer product; and

- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of acute toxicity, eye damage, skin irritation, pulmonary effects, skin sensitization, specific target organ toxicity, neurotoxicity, genetic toxicity, reproductive toxicity, developmental toxicity, carcinogenicity, and aquatic toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-21-201 (40 CFR 721.11851)

Chemical Name: 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-tetradecyl-, chloride (1:2); 1,3-Propanediaminium, N1-hexadecyl-2-

hydroxy-N1,N1,N3,N3,N3-pentamethyl-, chloride (1:2); 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-octadecyl-, chloride (1:2); 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-octadecen-1-yl-, chloride (1:2).

CASRNs: 1622255-87-1; 63560-76-9; 197862-16-1; and 2748681-38-9.

Effective Date of TSCA Order: April 12, 2022.

Basis for TSCA Order: The PMN states that the use will be as a surfactant in a cationic latex asphalt emulsion formulation. Based on the intended use and structure, EPA has identified concerns for surfactant effects of the lung. Based on comparison to analogous chemical substances, EPA also identified concerns for skin irritation/corrosion, eye irritation/corrosion, mortality, systemic, and neurotoxic, and developmental effects. Based on comparison to analogous cationic (quaternary ammonium) surfactants, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 21 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No use of the PMN substance in consumer products;

- No manufacture, processing, or use of the PMN substance in any manner or method that results in inhalation exposure;

- No release of the PMN substance, or any waste stream containing the PMN substance, in surface water concentrations that exceed 21 ppb;

- Use of personal protective equipment where there is a potential for dermal exposure; and

- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity, acute toxicity, neurotoxicity, specific target organ toxicity, pulmonary

effects, developmental toxicity, skin irritation, skin corrosion, and eye damage testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order's restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-21-206 (40 CFR 721.11852)

Chemical Name: Alkanes, branched and linear (generic).

CASRN: Not available.

Effective Date of TSCA Order: March 25, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use of the PMN substance will be as a component of gasoline. Based on data on analogous mixtures, EPA has identified concerns for skin irritation, neurotoxicity, systemic toxicity, developmental toxicity, portal-of-entry effects via the inhalation route, and carcinogenicity. Based on data on representative constituents of the PMN substance, EPA has also identified concerns for eye irritation, acute toxicity, acute neurotoxicity, reproductive toxicity, portal-of-entry effects via the oral route, aspiration hazard, and genetic toxicity. Based on information provided in the SDS, EPA has also identified concerns for aspiration hazard, flammability, skin irritation, eye irritation, and acute neurotoxicity. Based on the chemical composition, EPA has also identified hydrocarbon pneumonia/aspiration hazard. EPA also assumes respiratory tract irritation is a hazard. Based on comparison to analogous neutral organic substances, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 3 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No manufacture, processing, or use of the PMN substance other than for use as a fuel, fuel additive, or regulated blendstock subject to 40 CFR part 79 or 1090, including as a component of gasoline or ethanol base fuel (E85);
- Use of personal protective equipment where there is a potential for dermal exposure; and
- Establishment of a hazard communication program.

The proposed SNUR would designate as a "significant new use" the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of skin irritation, eye irritation, respiratory depression/irritation, hydrocarbon pneumonia/aspiration hazard, reproductive developmental toxicity, systemic toxicity, genetic toxicity, carcinogenicity, aquatic toxicity, and consumer inhalation exposure at gas stations testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order's restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Numbers (Proposed CFR Citations): P-22-29 (40 CFR 721.11853), P-22-30 (40 CFR 721.11854), and P-22-31 (40 CFR 721.11855)

Chemical Names: Polyester with 1,4-benzenedicarboxylic acid, 1,4-dimethyl 1,4-benzenedicarboxylate, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[isocyanatobenzene] (generic) (P-22-29), Polyester with 1,4-benzenedicarboxylic acid, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[4-isocyanatobenzene] (generic) (P-22-30), and Polyester with 1,4-benzenedicarboxylic acid, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[isocyanatobenzene] (generic) (P-22-31).

CASRNs: Not available.

Effective Date of TSCA Order: January 6, 2023.

Basis for TSCA Order: The PMNs state that the uses will be as industrial adhesives. Based on comparison to analogous diisocyanates, EPA has identified concerns for irritation to skin, eyes, and respiratory tract, skin and

respiratory sensitization, and pulmonary toxicity for the low molecular weight species present in the PMN substances. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No manufacture, processing, or use of the PMN substances in any manner that results in inhalation exposure;
- No use of the PMN substances in consumer products;
- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a "significant new use" the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of pulmonary effects, skin irritation, eye irritation, skin sensitization, and specific target organ toxicity testing may be potentially useful to characterize the health effects of the PMN substances. Although the Order does not require these tests, the Order's restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P-22-55 (40 CFR 721.11856)

Chemical Name: Aromatic sulfonium tricyclo fluoroalkyl sulfonic acid salt (generic).

CASRN: Not available.

Effective Date of TSCA Order: October 31, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use of the PMN substance will be as a photoacid generator (PAG) for use in electronics industry. Based on the physical/chemical properties of the PMN substance (as described in the New Chemical Program's PBT category at 64 FR 60194; November 1999) and in the absence of data, the PMN substance is a potentially persistent, bioaccumulative, and toxic (PBT) chemical. EPA estimates that the PMN

substance will persist in the environment for more than six months and estimates a bioaccumulation factor of greater than or equal to 1,000. Based on the reactivity of the PMN substance, EPA has identified concerns for photosensitization. Based on test data on the PMN substance and information provided in the SDS, EPA has also identified concerns for eye irritation and corrosion, skin and eye corrosion, and corrosion to mucous membranes. Based on data on sulfonium compounds, EPA has also identified concerns for acute toxicity, irritation to the skin, eyes, and respiratory tract, eye corrosion, ocular lethality, neurological effects, and systemic effects for the sulfonium cation of the PMN substance. Based on comparison to analogous substances, EPA has also identified concerns for genetic and acute toxicity, eye irritation and corrosion, and systemic effects. Based on perfluoro analogue data, EPA has also identified concerns for thyroid, liver, and reproductive (developmental) toxicity for the anion of the PMN substance. Based on data on a potential incineration product, EPA identified hazards for local and systemic effects. EPA was unable to estimate the environmental hazard of this substance. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No manufacture of the PMN substance beyond the time limits specified in the Order without submittal to EPA the results of certain testing described in the Testing section of the Order;
- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS;
- No modification of the processing or use of the PMN substance in any way that generates a vapor, dust, mist, or aerosol in a non-enclosed process;
- Use of the PMN substance only as a photoacid generator;
- No domestic manufacture of the PMN substance (*i.e.*, import only);
- Import of the PMN substance only in solution, or in any form in sealed containers weighing 5 kilograms or less; and

- No exceedance of the confidential annual importation volume listed in the Order.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information about the physical/chemical properties, fate, bioaccumulation, environmental hazard, and human health effects of the PMN substance may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. The submitter has agreed not to exceed the time limits specified in the Order without performing the required Tier I and Tier II testing outlined in the Testing section of the Order.

PMN Number (Proposed CFR Citation): P–22–69 (40 CFR 721.11857)

Chemical Name: Fluoroheteroacid, metal salt (generic).

CASRN: Not available.

Effective Date of TSCA Order: November 24, 2022.

Basis for TSCA Order: The PMN states that the generic (non-confidential) use will be as a component in batteries. Based on submitted test data on the PMN substance, EPA has identified concerns for acute toxicity, skin, respiratory and eye corrosion, skin sensitization, and systemic effects. Based on data on the hydrolysis product, EPA has also identified concerns for systemic, reproductive, and developmental effects. Based on submitted test data on the PMN substance and comparison to analogous chemical substances, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 380 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- Use of personal protective equipment where there is a potential for dermal exposure;
- Use of a NIOSH-certified particulate respirator with an APF of at least 50 where there is a potential for inhalation exposure;
- No use of the PMN substance in a consumer product;
- No release of the PMN substance resulting in surface water concentrations that exceed 380 ppb; and

- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of pulmonary effects, developmental effects, specific target organ toxicity, and chronic fish toxicity testing may be potentially useful to characterize the health and environmental effects of the PMN substance. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Number (Proposed CFR Citation): P–22–147 (40 CFR 721.11858)

Chemical Name: Hydrocarbons, C5–10.

CASRN: 2779559–23–6.

Effective Date of TSCA Order: November 2, 2022.

Basis for TSCA Order: The PMN states that the use will be as a feedstock for gasoline for racing fuels. Based on comparison to analogous chemical mixtures and data on the worst case constituents of the PMN substance, EPA has identified concerns for irritation to the skin, eye, and respiratory tract, acute toxicity, developmental and reproductive effects, systemic effects, aspiration hazard, genetic toxicity, and carcinogenicity. Based on data on constituents of the mixture, EPA predicts toxicity to aquatic organisms may occur at concentrations that exceed 25 ppb. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substance may present an unreasonable risk of injury to human health and the environment. To protect against these risks, the Order requires:

- Import, processing, and use of the PMN substance only as a feedstock for gasoline containing no more than 64% of the PMN substance where the imported gasoline mixture is regulated under applicable EPA regulations for fuels, fuel additives, and regulated blendstocks (40 CFR part 1090), fuel additives, and regulated blendstocks (40

CFR part 1090), registration of fuels and fuel additives (40 CFR part 79).

- No domestic manufacture of the PMN substance (*i.e.*, import only);
- Use of personal protective equipment where there is a potential for dermal exposure; and
- Establishment of a hazard communication program.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. EPA has determined that the results of aquatic toxicity, skin irritation, eye irritation, reproductive/developmental toxicity, systemic toxicity, genetic toxicity, and carcinogenicity testing may be potentially useful to characterize the health and environmental effects of the PMN substances. Although the Order does not require these tests, the Order’s restrictions remain in effect until the Order is modified or revoked by EPA based on submission of this or other relevant information.

PMN Numbers (Proposed CFR Citations): P-22-150 (40 CFR 721.11859), P-22-152 (40 CFR 721.11860), P-22-161 (40 CFR 721.11861), and P-22-177 (40 CFR 721.11862).

Chemical Names: Sulfonium, tricarboxylic-, alpha, alpha, beta, beta-polyhalopolyhydro-heteropolycyclic-5-alkanesulfonate (1:1) (generic) (P-22-150), Sulfonium, tricarboxylic-, 2-heteroatom-substituted-4-alkylcarbomonocyclecarboxylate (1:1) (generic) (P-22-152), Sulfonium, tricarboxylic-, salt with [polyhydro-2-alkyl-5-(polyhalo-2-heteroalkyl)-alkano-1,3-hetropolycyclic]alkyl polyhaloaryl ester (1:1) (generic) (P-22-161), and Sulfonium, tricarboxylic-, alpha, alpha, beta, beta-polyhalopolyhydro-heteropolycyclic-5-alkanesulfonate (1:1) (generic) (P-22-177).

CASRs: Not available.

Effective Date of TSCA Order: February 6, 2023.

Basis for TSCA Order: The PMNs state that the generic (non-confidential) use of the PMN substances will be for photolithography. Based on the physical/chemical properties of the PMN substances (as described in the New Chemical Program’s PBT category at 64 FR 60194; November 1999) and in the absence of data, the PMN substances are potentially persistent, bioaccumulative, and toxic (PBT)

chemicals. EPA estimates that the PMN substances will persist in the environment for more than six months and have unknown bioaccumulation potential. EPA also estimates that the cation photodegradation products will persist in the environment for more than two months and have bioaccumulation factors over 1000. Based on data on sulfonium compounds, EPA has identified concerns for acute toxicity, irritation to the skin, eyes, and respiratory tract, eye corrosion, ocular lethality, neurological effects, and systemic effects for the sulfonium cations of the PMN substances. Based on the photoreactivity of the PMN substances, EPA has also identified concerns for photosensitization. Based on the reactivity of the PMN substances, EPA has also identified irritation to the skin, eyes, and respiratory tract. Based on comparison to analogous substances, EPA has also identified concerns for mutagenicity. Based on OECD QSAR Toolbox results, EPA has also identified hazards for skin sensitization for P-22-150, P-22-161, and P-22-177, and carcinogenicity for P-22-161 and P-22-177, and skin sensitization and carcinogenicity for the anion of P-22-161. Based on anion analogue data, EPA has also identified concerns for acute toxicity, skin irritation, eye corrosion, GI tract irritation, and systemic, reproductive and developmental effects for P-22-150, P-22-161, and P-22-177. Based on data on a potential incineration by-product, EPA has also identified concerns for local, neurotoxic, and systemic effects. EPA was unable to estimate the environmental hazard of these substances. The Order was issued under TSCA sections 5(a)(3)(B)(ii)(I) and 5(e)(1)(A)(ii)(I), based on a finding that in the absence of sufficient information to permit a reasoned evaluation, the substances may present an unreasonable risk of injury to human health or the environment. To protect against these risks, the Order requires:

- No manufacture of any of the PMN substances beyond the time limits specified in the Order without submittal to EPA the results of certain testing described in the Testing section of the Order;
- Use of personal protective equipment where there is a potential for dermal exposure;
- Establishment of a hazard communication program, including human health and environmental precautionary statements on each label and in the SDS;
- No processing of the PMN substances in any way that generates a

vapor, dust, mist, or aerosol in a non-enclosed process;

- Use of the PMN substances only for the confidential use stated in the Order;
- No domestic manufacture of the PMN substances (*i.e.*, import only);
- Import of the PMN substances only in solution, or in any form in sealed containers weighing 5 kilograms or less; and
- No exceedance of the confidential annual importation volumes listed in the Order.

The proposed SNUR would designate as a “significant new use” the absence of these protective measures.

Potentially Useful Information: EPA has determined that certain information about the physical/chemical properties, fate, bioaccumulation, environmental hazard, and human health effects of the PMN substances may be potentially useful in support of a request by the PMN submitter to modify the Order, or if a manufacturer or processor is considering submitting a SNUN for a significant new use that will be designated by this SNUR. The submitter has agreed not to exceed the time limits specified in the Order without performing the required Tier I and Tier II testing outlined in the Testing section of the Order.

IV. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at <https://www.epa.gov/laws-regulations-and-executive-orders>.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 14094: Modernizing Regulatory Review

This action proposes to establish SNURs for new chemical substances that were the subject of PMNs. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866 (58 FR 51735, October 4, 1993), as amended by Executive Order 14094 (88 FR 21879, April 11, 2023).

B. Paperwork Reduction Act (PRA)

According to the PRA (44 U.S.C. 3501 *et seq.*), an agency may not conduct or sponsor, and a person is not required to respond to a collection of information that requires OMB approval under PRA, unless it has been approved by OMB and displays a currently valid OMB control number. The OMB control numbers for EPA’s regulations in title 40 of the CFR, after appearing in the **Federal Register**, are listed in 40 CFR part 9, and included on the related

collection instrument or form, if applicable.

The information collection requirements related to SNURs have already been approved by OMB pursuant to PRA under OMB control number 2070–0038 (EPA ICR No. 1188). This action does not impose any burden requiring additional OMB approval. If an entity were to submit a SNUN to the Agency, the annual burden is estimated to average between 30 and 170 hours per submission. This burden estimate includes the time needed to review instructions, search existing data sources, gather and maintain the data needed, and complete, review, and submit the required SNUN.

EPA always welcomes your feedback on the burden estimates. Send any comments about the accuracy of the burden estimate, and any suggested methods for improving the collection instruments or instruction or minimizing respondent burden, including through the use of automated collection techniques.

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 (5 U.S.C. 601 *et seq.*). The requirement to submit a SNUN applies to any person (including small or large entities) who intends to engage in any activity described in the final rule as a “significant new use.” Because these uses are “new,” based on all information currently available to EPA, EPA has concluded that no small or large entities presently engage in such activities.

A SNUR requires that any person who intends to engage in such activity in the future must first notify EPA by submitting a SNUN. Although some small entities may decide to pursue a significant new use in the future, EPA cannot presently determine how many, if any, there may be. However, EPA’s experience to date is that, in response to the promulgation of SNURs covering over 1,000 chemicals, the Agency receives only a small number of notices per year. For example, the number of SNUNs received was 16 in Federal fiscal year (FY) FY2018, five in FY2019, seven in FY2020, 13 in FY2021, 11 in FY2022, and 15 in FY2023, and only a fraction of these submissions were from small businesses.

In addition, the Agency currently offers relief to qualifying small businesses by reducing the SNUN submission fee from \$37,000 to \$6,480. This lower fee reduces the total reporting and recordkeeping cost of submitting a SNUN to about \$14,500 per

SNUN submission for qualifying small firms. Therefore, the potential economic impacts of complying with these proposed SNURs are not expected to be significant or adversely impact a substantial number of small entities. In a SNUR that published in the **Federal Register** of June 2, 1997 (62 FR 29684) (FRL–5597–1), the Agency presented its general determination that SNURs are not expected to have a significant economic impact on a substantial number of small entities, which was provided to the Chief Counsel for Advocacy of the Small Business Administration.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of \$100 million or more in any one year (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. Based on EPA’s experience with proposing and finalizing SNURs, State, local, and Tribal governments have not been impacted by SNURs. In addition, the estimated costs of this action to the private sector do not exceed \$183 million or more in any one year (the 1995 dollars are adjusted to 2023 dollars for inflation using the GDP implicit price deflator). The estimated costs for this action are discussed in Unit I.D.

E. Executive Order 13132: Federalism

This action will not have federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999), because it is not expected to have a substantial direct effect on 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. Accordingly, the requirements of Executive Order 13132 do not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action will not have Tribal implications as specified in Executive Order 13175 (65 FR 67249, November 9, 2000), because it is not expected to have substantial direct effects on Indian Tribes, significantly or uniquely affect the communities of Indian Tribal governments and does not involve or impose any requirements that affect Indian Tribes. Accordingly, the requirements of Executive Order 13175 do not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), because it does not concern an environmental health or safety risk. Since this action does not concern human health, EPA’s 2021 Policy on Children’s Health also does not apply. Although the establishment of these SNURs do not address an existing children’s environmental health concern because the chemical uses involved are not ongoing uses, SNURs require that persons notify EPA at least 90 days before commencing manufacture (defined by statute to include import) or processing of any of these chemical substances for an activity that is designated as a significant new use by this rulemaking. This notification allows EPA to assess the conditions of use to identify potential risks and take appropriate actions before the activities commence.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a “significant energy action” as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act (NTTAA)

This action does not involve any technical standards subject to NTTAA section 12(d) (15 U.S.C. 272 note).

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

This action does not concern human health or environmental conditions and therefore cannot be evaluated with respect to the potential for disproportionate impacts on non-white and low-income populations in accordance with Executive Order 12898 (59 FR 7629, February 16, 1994) and Executive Order 14096 (88 FR 25251, April 26, 2023). Although this action does not concern human health or environmental conditions, the premanufacture notifications required by these SNURs allow EPA to assess the conditions of use to identify potential disproportionate risks and take appropriate actions before the activities commence.

List of Subjects in 40 CFR Part 721

Environmental protection, Chemicals, Hazardous substances, Reporting and recordkeeping requirements.

Dated: June 4, 2024.

Mary Elissa Reaves,

Director, Office of Pollution Prevention and Toxics.

Therefore, for the reasons stated in the preamble, EPA proposes to amend 40 CFR chapter I as follows:

PART 721—SIGNIFICANT NEW USES OF CHEMICAL SUBSTANCES

■ 1. The authority citation for part 721 continues to read as follows:

Authority: 15 U.S.C. 2604, 2607, and 2625(c).

■ 2. Add §§ 721.11829 through 721.11862 to subpart E to read as follows:

Subpart E—Significant New Uses for Specific Chemical Substances

Sec.

* * * * *

721.11829 Unsaturated dicarboxylic acid polymer with 2-(dialkylamino)alkyl-alkyl-alkanoate, N,N-dialkyl-alkene amide, 2-propenamide and salt of alkyl-substituted alkene sulfonate (generic).

721.11830 Octadecanoic acid, 12-hydroxy-, polymer with aziridine, 2-oxepanone and tetrahydro-2H-pyran-2-one, reaction products with disubstituted heteropolycyclic (generic).

721.11831 Ethyl 4-alkyl-2-oxocycloalkanecarboxylate (generic).

721.11832 Sulfonium, tricarboxylic-, polyfluoropolyhydro-2,2-dicarboxylic-4,7-methano-1,3-benzodioxole-5-alkanesulfonate (1:1) (generic).

721.11833 Sulfonium, tricarboxylic-, 2-[3,5-bis(haloalkyl)phenyl]-.alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2-alkyl-4,7-alkano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

721.11834 Sulfonium, tricarboxylic-, 2-(4-alkoxyhalocarbomonocyclic)-.alpha., .alpha., .beta., .beta.-polyhalopolyhydro-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

721.11835 Sulfonium, monocarbocyclicbisarylpolyhaloalkyl, .alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2,2-diaryl-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

721.11836 Sulfonium, bis(3,4-polyhalocarbocyclic)aryl-, .alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2,2-diaryl-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

721.11837 Sulfonium, tricarboxylic-, 2-heteroatom-substituted-4-(halocarbocyclic)carboxylate (1:1) (generic).

721.11838 Fatty acids, reaction products with polyamine-polyacid polymer and fatty acid (generic).

721.11839 Poly[oxy(methyl-1,2-ethandiyl)], .alpha.,-(dithiocarboxy)-.omega.-(1-methylethoxy)-, sodium salt (1:1).

721.11840 Poly[oxy(methyl-1,2-ethandiyl)], .alpha.,-(dithiocarboxy)-.omega.-butoxy-, sodium salt (1:1).

721.11841 1,4-Cyclohexanedicarboxylic acid, 1,4-dinonyl ester, branched and linear.

721.11842 1,3-Butadiene, homopolymer, hydrogenated, 2-(ethenyl)ethyl-terminated.

721.11843 Lignin, modified, reaction products with alkylamine by-products, hydrochlorides (generic).

721.11844 Lignin, modified, reaction products with alkylamine by-products (generic).

721.11845 Sulfonium, triphenyl-, salt with fluoroalkyl 5-sulfobicyclo[2.2.1]heptane carboxylate (1:1) (generic).

721.11846 Triazine-trione, tris(isocyanatoalkyl)-, polymer with substituted diisocyanato alkylcarbomonocycle, hydro-hydroxypoly(oxyalkanediy) and hydro-hydroxypoly[oxy(alkyl-alkanediy)], aliphatic alkyl amine-blocked (generic).

721.11847 Lithium metal oxide (generic).

721.11848 Soybean oil, oleic acid-high, epoxidized.

721.11849 Sulfonium, (halocarbomonocycle)diphenyl-, salt with 1-heterosubstituted-2-methylalkyl trihalobenzoate (1:1) (generic).

721.11850 1,6-Disubstituted hexane (generic).

721.11851 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-tetradecyl-, chloride (1:2); 1,3-Propanediaminium, N1-hexadecyl-2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-, chloride (1:2); 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-octadecyl-, chloride (1:2); 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-octadecen-1-yl, chloride (1:2).

721.11852 Alkanes, branched and linear (generic).

721.11853 Polyester with 1,4-benzenedicarboxylic acid, 1,4-dimethyl 1,4-benzenedicarboxylate, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis(isocyanatobenzene) (generic).

721.11854 Polyester with 1,4-benzenedicarboxylic acid, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[4-isocyanatobenzene] (generic).

721.11855 Polyester with 1,4-benzenedicarboxylic acid, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-

methylenebis(isocyanatobenzene) (generic).

721.11856 Aromatic sulfonium tricyclo fluoroalkyl sulfonic acid salt (generic).

721.11857 Fluoroheteroacid, metal salt (generic).

721.11858 Hydrocarbons, C5-10.

721.11859 Sulfonium, tricarboxylic-, alpha, alpha, beta, beta-polyhalopolyhydro-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

721.11860 Sulfonium, tricarboxylic-, 2-heteroatom-substituted-4-alkylcarbomonocyclecarboxylate (1:1) (generic).

721.11861 Sulfonium, tricarboxylic-, salt with [polyhydro-2-alkyl-5-(polyhalo-2-heteroalkyl)-alkano-1,3-heteropolycyclic]alkyl polyhaloaryl ester (1:1) (generic).

721.11862 Sulfonium, tricarboxylic-, alpha, alpha, beta, beta-polyhalopolyhydro-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

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§ 721.11829 Unsaturated dicarboxylic acid polymer with 2-(dialkylamino)alkyl-alkyl-alkanoate, N,N-dialkyl-alkene amide, 2-propenamide and salt of alkyl-substituted alkene sulfonate (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as unsaturated dicarboxylic acid polymer with 2-(dialkylamino)alkyl-alkyl-alkanoate, N,N-dialkyl-alkene amide, 2-propenamide and salt of alkyl-substituted alkene sulfonate (PMN P-20-96) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (3) through (5), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 10. For purposes of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (f), (g)(1), (3), and (5). For purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this

substance may cause: skin corrosion and eye irritation. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to manufacture the substance unless the percentage of the confidential reactant listed in the Order represents 10% or less (by weight) of the substance.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=490.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11830 Octadecanoic acid, 12-hydroxy-, polymer with aziridine, 2-oxepanone and tetrahydro-2H-pyran-2-one, reaction products with disubstituted heteropolycycle (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as octadecanoic acid, 12-hydroxy-, polymer with aziridine, 2-oxepanone and tetrahydro-2H-pyran-2-one, reaction products with disubstituted heteropolycycle (PMN P-21-2) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or cured.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health

(NIOSH) assigned protection factor (APF) of at least 50 during non-spray applications or 10,000 during spray applications. For purposes of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (f), (g)(1), (3), and (5). For purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause: skin irritation, eye irritation, and specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(o).

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=50.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11831 Ethyl 4-alkyl-2-oxocycloalkanecarboxylate (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as ethyl 4-alkyl-2-oxocycloalkanecarboxylate (PMN P-21-19) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance when the substance is present at less than 0.5% in formulation.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes

of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (f), (g)(1), (3), and (5). For purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause: specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(f). It is a significant new use to use the substance other than as a fragrance ingredient for making fragrance oils by blending (mixing) with other fragrance ingredients. It is a significant new use to use the substance at a concentration of 0.5% (by weight) or greater in consumer products.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11832 Sulfonium, tricarboxylic-, polyfluoropolyhydro-2,2-dicarboxylic-4,7-methano-1,3-benzodioxole-5-alkanesulfonate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, tricarboxylic-, polyfluoropolyhydro-2,2-dicarboxylic-4,7-methano-1,3-benzodioxole-5-alkanesulfonate (1:1) (PMN P-21-48) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering

control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity.

Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11833 Sulfonium, tricarboxylic-, 2-[3,5-bis(haloalkyl)phenyl]-.alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2-alkyl-4,7-alkano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, tricarboxylic-, 2-[3,5-bis(haloalkyl)phenyl]-.alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2-alkyl-4,7-alkano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (PMN P-21-130) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article

used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: eye irritation, acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11834 Sulfonium, tricarboxylic-, 2-(4-alkoxyhalocarbomonocyclic)-.alpha., .alpha., .beta., .beta.-polyhalopolyhydro-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, tricarboxylic-, 2-(4-alkoxyhalocarbomonocyclic)-.alpha., .alpha., .beta., .beta.-polyhalopolyhydro-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1)

(PMN P-21-131) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11835 Sulfonium, monocarbocyclicbisarylpolymethacrylate, .alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2,2-diaryl-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, monocarbocyclicbisarylpolymethacrylate, .alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2,2-diaryl-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (PMN P-21-177) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part

apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11836 Sulfonium, bis(3,4-polyhalocarbocyclic)aryl-, .alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2,2-diaryl-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, bis(3,4-polyhalocarbocyclic)aryl-, .alpha., .alpha., .beta., .beta.-polyhalopolyhydro-2,2-diaryl-4,7-methano-1,3-heteropolycyclic-5-alkanesulfonate (1:1) (PMN P-21-204) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the

substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11837 Sulfonium, tricarbo-cyclic-, 2-heteroatom-substituted-4-(halocarbocyclic)carboxylate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, tricarbo-cyclic-, 2-heteroatom-substituted-4-(halocarbocyclic)carboxylate (1:1) (PMN P-22-12) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: eye irritation, acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized

System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11838 Fatty acids, reaction products with polyamine-polyacid polymer and fatty acid (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as fatty acids, reaction products with polyamine-polyacid polymer and fatty acid (PMN P-21-55) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance when they have been completely reacted (cured).

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (a)(4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 10. For purposes of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), (g)(1), and (5). For purposes of § 721.72(e), the concentration is set at

1.0%. For purposes of § 721.72(g)(1), this substance may cause: skin irritation, eye irritation, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* It is a significant new use to manufacture the substance in a manner that results in an amine value of more than 127 mg KOH/g.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11839 Poly[oxy(methyl-1,2-ethandiyl)], .alpha.-(dithiocarboxy)-.omega.-(1-methylethoxy)-, sodium salt (1:1).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified as poly[oxy(methyl-1,2-ethandiyl)], .alpha.-(dithiocarboxy)-.omega.-(1-methylethoxy)-, sodium salt (1:1) (PMN P-21-71; CASRN 2304726-53-0) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (a)(4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 10. For purposes of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), (g)(1), (3), and (5). For the purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause skin irritation, eye irritation, reproductive toxicity, and

specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80 (f). It is a significant new use to use the substance other than as a floatation aid in sulfide ore mining at mines with valid permits (State, Federal, or Tribal) for operations and waste handling.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=150.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11840 Poly[oxy(methyl-1,2-ethandiyl)], .alpha.-(dithiocarboxy)-.omega.-butoxy-, sodium salt (1:1).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified as poly[oxy(methyl-1,2-ethandiyl)], .alpha.-(dithiocarboxy)-.omega.-butoxy-, sodium salt (1:1) (PMN P-21-72; CASRN 2304726-56-3) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3) through (5), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (a)(4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 10. For purposes of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a)

through (f), (g)(1), (3), and (5). For the purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause skin irritation, eye irritation, reproductive toxicity, and specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(f). It is a significant new use to use the substance other than as a floatation aid in sulfide ore mining at mines with valid permits (State, Federal, or Tribal) for operations and waste handling.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=150.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11841 1,4-Cyclohexanedicarboxylic acid, 1,4-dinonyl ester, branched and linear.

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified as 1,4-cyclohexanedicarboxylic acid, 1,4-dinonyl ester, branched and linear (PMN P-21-73; CASRN 2449089-78-3) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely bound in a PVC article.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes

of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), (g)(1), (3), and (5). For the purposes of § 721.72(e) the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause: reproductive toxicity and specific target organ toxicity. For the purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to process or use the substance other than as a plasticizer in polyvinyl chloride (PVC) articles. It is a significant new use to process the substance for use in a consumer product.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11842 1,3-Butadiene, homopolymer, hydrogenated, 2-(ethenyloxy)ethyl-terminated.

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified as 1,3-butadiene, homopolymer, hydrogenated, 2-(ethenyloxy)ethyl-terminated (PMN P-21-74; CASRN 2511154-73-5) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or cured.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative

control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), (g)(1), and (5). For purposes of § 721.72(g)(1), this substance may cause: respiratory sensitization, skin sensitization, germ cell mutagenicity, specific target organ toxicity, and reproductive toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(k) and (o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11843 Lignin, modified, reaction products with alkylamine by-products, hydrochlorides (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as lignin, modified, reaction products with alkylamine by-products, hydrochlorides (PMN P-21-89) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), (g)(1), (3), and (5). For the purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(ii) *Industrial, commercial, and consumer use.* It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure. It is a significant new use to manufacture, process, or use the substance in any manner that results in direct air releases to the environment except during loading or unloading of transport containers.

(iii) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=2.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (c), (f) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11844 Lignin, modified, reaction products with alkylamine by-products (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as lignin, modified, reaction products with alkylamine by-products (PMN P-21-90) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (f), and (g)(1), (3) and (5). For the purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized

System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure. It is a significant new use to manufacture, process, or use the substance in any manner that results in direct air releases to the environment except during loading or unloading of transport containers.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=12.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11845 Sulfonium, triphenyl-, salt with fluoroalkyl 5-sulfobicyclo[2.2.1]heptane carboxylate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, triphenyl-, salt with fluoroalkyl 5-sulfobicyclo[2.2.1]heptane carboxylate (1:1) (PMN P-21-124) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may

cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f) and (t). It is a significant new use to use the substance other than as an onium salt that generates strong or weak acid in lithography process. It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11846 Triazine-trione, tris(isocyanatoalkyl)-, polymer with substituted diisocyanato alkylcarbomonocycle, hydro-hydroxypoly(oxyalkanediyl) and hydro-hydroxypoly[oxy(alkyl-alkanediyl)], aliphatic alkyl amine-blocked (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as triazine-trione, tris(isocyanatoalkyl)-, polymer with substituted diisocyanato alkylcarbomonocycle, hydro-hydroxypoly(oxyalkanediyl) and hydro-hydroxypoly[oxy(alkyl-alkanediyl)], aliphatic alkyl amine-blocked (PMN P-21-137) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or cured.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), and (c). When determining which persons are reasonably likely to be exposed as

required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), and (g)(1), (3) and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin corrosion, skin irritation, skin sensitization, serious eye damage, eye irritation, genetic toxicity, reproductive toxicity, specific target organ toxicity, and respiratory irritation. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=15.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11847 Lithium metal oxide (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as lithium metal oxide (PMN P-21-138) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (3) through (5), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures)

shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 1,000 if the dust control capture and reduction rate is at less than 90% or at least 50 if the dust control capture and reduction rate is at least 90%. For purposes of § 721.63(b), the concentration is set at 1.0%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (f), (g)(1), and (5). For the purposes of § 721.72(e) the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause: reproductive toxicity and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f) and (o). It is a significant new use to use the substance other than in the manufacture of batteries.

(iv) *Disposal.* Requirements as specified in § 721.85(a)(1) and (2), (b)(1) and (2), and (c)(1) and (2).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (j) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11848 Soybean oil, oleic acid-high, epoxidized.

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified as soybean oil, oleic acid-high, epoxidized (PMN P-21-140; CASRN 2410202-82-1) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative

control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (f), (g)(1), (3), and (5). For purposes of § 721.72(e), the concentration is set at 0.1%. For purposes of § 721.72(g)(1), this substance may cause: skin irritation, eye irritation, respiratory sensitization, carcinogenicity, reproductive toxicity, and specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* It is a significant new use to use the substance other than as a chemical intermediate to prepare acrylate-containing oil, which is subsequently polymerized to prepare a viscosity modifier for asphalt. It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11849 Sulfonium, (halocarbo monocycle)diphenyl-, salt with 1-heterosubstituted-2-methylalkyl trihalobenzoate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, (halocarbo monocycle)diphenyl-, salt with 1-heterosubstituted-2-methylalkyl trihalobenzoate (1:1) (PMN P-21-180) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic

processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11850 1,6-Disubstituted hexane (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as 1,6-disubstituted hexane (PMN P-21-199) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the

substance after they have been reacted or destroyed.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1) and (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (3), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, eye irritation, respiratory sensitization, skin sensitization, genetic toxicity, carcinogenicity, reproductive toxicity, and specific target organ toxicity. For the purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposures.

(iv) *Disposal.* It is a significant new use to dispose of the substance other than by hazardous waste incineration.

(v) *Release to water.* Requirements as specified in § 721.90(a)(1), (b)(1), and (c)(1).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11851 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-tetradecyl-, chloride (1:2); 1,3-Propanediaminium, N1-hexadecyl-2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-, chloride (1:2); 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-octadecyl-, chloride (1:2); 1,3-Propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-octadecen-1-yl, chloride (1:2).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified as 1,3-propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-tetradecyl-, chloride (1:2); 1,3-propanediaminium, N1-hexadecyl-2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-, chloride (1:2); 1,3-propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-octadecyl-, chloride (1:2); 1,3-propanediaminium, 2-hydroxy-N1,N1,N1,N3,N3-pentamethyl-N3-octadecen-1-yl, chloride (1:2) (PMN P-21-201; CASRNs 1622255-87-1; 63560-76-9; 197862-16-1; and 2748681-38-9) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or cured.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (f), (g)(1), (3), and (5). For purposes of § 721.72(e), the concentration is set at 1.0%. For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin corrosion, skin irritation, serious eye damage, eye irritation, reproductive toxicity, and specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(o). It is a

significant new use to manufacture, process, or use the substance in any manner or method that results in inhalation exposure.

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=21.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11852 Alkanes, branched and linear (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as alkanes, branched and linear (PMN P-21-206) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into a fuel.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1) and (3), (b) and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer use.* It is a significant new use to manufacture, process, or use the substance other than as a fuel, fuel additive, or regulated blendstock subject to 40 CFR parts 79 or 1090, including as a component of gasoline or ethanol base fuel (E85).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable

to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11853 Polyester with 1,4-benzenedicarboxylic acid, 1,4-dimethyl 1,4-benzenedicarboxylate, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[isocyanatobenzene] (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as polyester with 1,4-benzenedicarboxylic acid, 1,4-dimethyl 1,4-benzenedicarboxylate, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[isocyanatobenzene] (PMN P-22-29) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or cured.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1) and (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), and (5). For purposes of § 721.72(g)(1), this substance may cause: skin irritation, eye irritation, respiratory sensitization, skin sensitization, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11854 Polyester with 1,4-benzenedicarboxylic acid, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[4-isocyanatobenzene] (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as polyester with 1,4-benzenedicarboxylic acid, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[4-isocyanatobenzene] (PMN P-22-30) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or cured.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1) and (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), and (5). For purposes of § 721.72(g)(1), this substance may cause: skin irritation, eye irritation, respiratory sensitization, skin sensitization, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(o). It is a

significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11855 Polyester with 1,4-benzenedicarboxylic acid, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[isocyanatobenzene] (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as polyester with 1,4-benzenedicarboxylic acid, 2,2-dimethyl-1,3-propanediol, dodecanedioic acid, 1,2-ethanediol, aliphatic polyester, 3-hydroxy-2,2-dimethylpropyl 3-hydroxy-2,2-dimethylpropanoate, 1,3-isobenzofurandione and 1,1'-methylenebis[isocyanatobenzene] (PMN P-22-31) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or cured.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1) and (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), and (5). For purposes of § 721.72(g)(1), this substance may cause: skin irritation, eye irritation, respiratory sensitization, skin sensitization, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and

Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(o). It is a significant new use to manufacture, process, or use the substance in any manner that results in inhalation exposure.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11856 Aromatic sulfonium tricyclo fluoroalkyl sulfonic acid salt (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as aromatic sulfonium tricyclo fluoroalkyl sulfonic acid salt (PMN P-22-55) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: skin irritation, acute toxicity, skin corrosion, skin sensitization, eye irritation, serious eye damage, specific target organ toxicity, genetic toxicity, and reproductive (developmental) toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA

Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f) and (t). It is a significant new use to use the substance other than as a photoacid generator. It is a significant new use to import the substance other than in solution, unless in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 18 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11857 Fluoroheteroacid, metal salt (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as fluoroheteroacid, metal salt (PMN P-22-69) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into an article.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (3) through (5), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1) and (4), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(a)(5), respirators must provide a National Institute for Occupational Safety and Health (NIOSH) assigned protection factor (APF) of at least 50.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (3), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin corrosion, serious eye damage, skin

sensitization, reproductive toxicity, and specific target organ toxicity. For purposes of § 721.72(g)(3), this substance may be: toxic to aquatic life. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(o).

(iv) *Release to water.* Requirements as specified in § 721.90(a)(4), (b)(4), and (c)(4), where N=380.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), and (k) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11858 Hydrocarbons, C5-10.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as hydrocarbons, C5-10 (PMN P-22-147; CASRN 2779559-23-6) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been incorporated into gasoline.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1) and (3), (b), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible. For purposes of § 721.63(b), the concentration is set at 0.1%.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a).

(iii) *Industrial, commercial, and consumer use.* Requirements as specified in § 721.80(f). It is a significant new use to import, process, or use the substance other than as a feedstock for gasoline containing no more than 64% of the substance where the imported gasoline mixture is regulated under

applicable EPA regulations for fuels, fuel additives, and regulated blendstocks (40 CFR part 1090), fuel additives, and regulated blendstocks (40 CFR part 1090), registration of fuels and fuel additives (40 CFR part 79).

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i), are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11859 Sulfonium, tricarbo-cyclic-, alpha, alpha, beta, beta-polyhalopolyhydro-heteropolycyclic-5-alkanesulfonate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, tricarbo-cyclic-, alpha, alpha, beta, beta-polyhalopolyhydro-heteropolycyclic-5-alkanesulfonate (1:1) (PMN P-22-150) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA

Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 9 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11860 Sulfonium, tricarbo-cyclic-, 2-heteroatom-substituted-4-alkylcarbomonocyclecarboxylate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, tricarbo-cyclic-, 2-heteroatom-substituted-4-alkylcarbomonocyclecarboxylate (1:1) (PMN P-22-152) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.* Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.* Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may

cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 9 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11861 Sulfonium, tricarbo-cyclic-, salt with [polyhydro-2-alkyl-5-(polyhalo-2-heteroalkyl)- alkan-1,3-hetropolycyclic] alkyl polyhaloaryl ester (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, tricarbo-cyclic-, salt with [polyhydro-2-alkyl-5-(polyhalo-2-heteroalkyl)- alkan-1,3-hetropolycyclic]alkyl polyhaloaryl ester (1:1) (PMN P-22-161) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as

required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, carcinogenicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 9 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

§ 721.11862 Sulfonium, tricarbo-cyclic-, alpha, alpha, beta, beta-polyhalopolyhydro-hetropolycyclic-5-alkanesulfonate (1:1) (generic).

(a) *Chemical substance and significant new uses subject to reporting.*

(1) The chemical substance identified generically as sulfonium, tricarbo-cyclic-, alpha, alpha, beta, beta-polyhalopolyhydro-hetropolycyclic-5-alkanesulfonate (1:1) (PMN P-22-177) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section. The requirements of this section do not

apply to quantities of the substance after they have been completely reacted or adhered (during photolithographic processes) onto a semiconductor wafer surface or similar manufactured article used in the production of semiconductor technologies.

(2) The significant new uses are:

(i) *Protection in the workplace.*

Requirements as specified in § 721.63(a)(1), (2)(i) and (iii), (3), and (c). When determining which persons are reasonably likely to be exposed as required for § 721.63(a)(1), engineering control measures (e.g., enclosure or confinement of the operation, general and local ventilation) or administrative control measures (e.g., workplace policies and procedures) shall be considered and implemented to prevent exposure, where feasible.

(ii) *Hazard communication.*

Requirements as specified in § 721.72(a) through (d), (f), (g)(1), (2)(i) through (iii), (v), (3)(i) and (ii), and (5). For purposes of § 721.72(g)(1), this substance may cause: acute toxicity, skin irritation, serious eye damage, skin sensitization, genetic toxicity, reproductive toxicity, and specific target organ toxicity. Alternative hazard and warning statements that meet the criteria of the Globally Harmonized System and OSHA Hazard Communication Standard may be used.

(iii) *Industrial, commercial, and consumer activities.* Requirements as specified in § 721.80(f), (k), and (t). It is a significant new use to import the substance other than in solution or in sealed containers weighing 5 kilograms or less. It is a significant new use to process the substance in any way that generates dust, mist, or aerosol in a non-enclosed process. It is a significant new use to manufacture the substance longer than 9 months.

(b) *Specific requirements.* The provisions of subpart A of this part apply to this section except as modified by this paragraph (b).

(1) *Recordkeeping.* Recordkeeping requirements as specified in § 721.125(a) through (i) are applicable to manufacturers, importers, and processors of this substance.

(2) *Limitation or revocation of certain notification requirements.* The provisions of § 721.185 apply to this section.

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FEDERAL REGISTER PAGES AND DATE, JUNE

47439-47846.....	3
47847-48130.....	4
48131-48254.....	5
48255-48486.....	6
48487-48820.....	7
48821-49080.....	10
49081-49796.....	11

CFR PARTS AFFECTED DURING JUNE

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

200.....48131

3 CFR

Proclamations:

10766.....48223

10767.....48225

10768.....48227

10769.....48229

10770.....48231

10771.....48233

10772.....48233

10772.....48255

10773.....48487

10774.....49081

Administrative Orders:

Presidential Permits:

Presidential Permit of

May 31, 2024.....48243

Presidential Permit of

May 31, 2024.....48247

Presidential Permit of

May 31, 2024.....48251

5 CFR

900.....48821

1302.....48821

1303.....48821

6 CFR

Proposed Rules:

226.....47471

7 CFR

3.....48495

800.....48257

3550.....48499

8 CFR

208.....48710

235.....48710

1208.....48710

Proposed Rules:

106.....48339

9 CFR

11.....48131

Proposed Rules:

56.....49107

145.....49107

146.....49107

147.....49107

201.....49002

10 CFR

50.....49083

52.....49083

72.....47439

433.....48266

12 CFR

1033.....49084

13 CFR

107.....48132

120.....48132

125.....48266

128.....48266

142.....48132

146.....48132

14 CFR

39.....48500, 49091, 49094

71.....47847, 47848, 48269,

48271, 48504, 48506

97.....48135, 48136

Proposed Rules:

39.....47879, 48139, 48348

71.....49118

15 CFR

922.....48272

17 CFR

17.....47439

240.....47688

248.....47688

270.....47688

275.....47688

Proposed Rules:

40.....48968

18 CFR

35.....49280

50.....47460

380.....47460

Proposed Rules:

4.....48351

5.....48351

6.....48351

7.....48351

20 CFR

222.....47460

235.....47462

404.....48138

416.....48138

21 CFR

1.....47463

573.....48507

Proposed Rules:

1308.....48515

24 CFR

236.....47849, 49099

26 CFR

Proposed Rules:

1.....47792

29 CFR

1603.....47850

4001.....48291

4010.....48291

4022.....48291	Proposed Rules:	721.....49121, 49770	11.....47891
4041.....48291	151.....48515		73.....47891
4041A.....48291	165.....47472, 47884	42 CFR	74.....47891
4043.....48291		Proposed Rules:	
4044.....48291	34 CFR	412.....47884	48 CFR
4050.....48291	Proposed Rules:	413.....47884	225.....48330
4262.....48291	Ch. VI.....48356, 48517	431.....47884	502.....48330
4281.....48291		482.....47884	538.....48330
Proposed Rules:	36 CFR	485.....47884	552.....48330
1910.....49119	7.....47866	495.....47884	Proposed Rules:
	1225.....47467	512.....47884	2.....48540
31 CFR	Proposed Rules:		19.....48540, 48544
223.....48827	1.....48850	45 CFR	42.....48540
542.....48309, 48310	14.....48850	Proposed Rules:	52.....48540, 48544
587.....48324, 48838, 48840		5b.....48536	
594.....48841, 48842	39 CFR		49 CFR
597.....48842	111.....49056	46 CFR	Proposed Rules:
		Proposed Rules:	571.....48359
33 CFR	40 CFR	541.....48865	
100.....48509	52.....47468, 49100		50 CFR
165.....47464, 47467, 47854,	141.....49101	47 CFR	17.....48034
48325, 48327, 48328, 48509,	257.....48774	8.....48514	622.....47871, 48338, 49104
48844, 48846, 48848	261.....48511	9.....47869	648.....47872, 49105
173.....47855	Proposed Rules:	20.....48514	680.....47872
174.....47855	52.....47474, 47481, 47504,	64.....47869	Proposed Rules:
207.....47863	48523, 48532, 49120	Proposed Rules:	216.....47508
326.....47863	70.....47504	4.....48540	

LIST OF PUBLIC LAWS

Note: No public bills which have become law were received by the Office of the Federal Register for inclusion

in today's **List of Public Laws**.

Last List May 29, 2024

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